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FORECAST OF LONG-TERM COAL SUPPLY AND MINING CONDITIONS: MODEL DOCUMENTATION AND RESULTS

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FORECAST OF LONG-TERM COAL SUPPLY AND MINING CONDITIONS MODEL DOCUMENTATION AND RESULTS

Final Report
JPL Contract 955552

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Technical Content Statement

1 ABSTRACT

The report presents documentation and results for the Energy and Environmental Analysis, Inc , coal industry model The model was developed to support the Jet Propulsion Laboratory in its investigation of advanced underground coal extraction systems The model documentation includes the programming for the coal mining cost models and an accompanying users' manual, and a guide to reading model output. The methodology used in assembling the transportation, demand, and coal reserve components of the model are also described Results are presented for 1985 and 2000, including projections of coal production patterns and marginal prices, differentiated by coal sulfur content

2 SUMMARY

As part of its investigation of advanced underground coal extraction systems, the Jet Propulsion Laboratory contracted with Energy and Environmental Analysis, Inc (EEA) for development of a forecast of long-range coal prices and mining conditions. This report documents the coal industry model used to prepare the forecast and presents model results

The EEA coal model is designed to project, by sulfur type, future coal prices, transportation patterns, and the distribution of production between mining methods The model is designed so that the impact on coal prices of varying economic, technological and policy assumptions, such as variations in regional demand for coal of a particular sulfur content, can be readily investigated

Three elements particularly differentiate the EEA coal model from other approaches

1) The level of detail in reserve characterization

2) The level of detail in the mine costing functions

3) Specification of the portion of future coal demand which will have to comply with the revised NSPS regulations (NSPS II), and inclusion of the dry scrubbing technology which will generally be used to meet the NSPS II standard

These and the other aspects of the model are discussed below

2.1 MODEL STRUCTURE

The model divides the U.S into 15 supply and 15 demand regions (see Tables 2-1 and 2-2) Each supply region is divided into dozens of "reserve blocks" of varying sizes, each of which has a production cost

TABLE 2-1

DEMAND REGIONS

1)
- New England
- New York

2)
- New Jersey
- Delaware
- Maryland

3)
- Pennsylvania

4)
- Ohio

5)
- Virginia
- North Carolina

6)
- South Carolina
- Georgia
- Florida

7)
- Alabama
- Mississippi

8)
- Texas
- Louisiana

9)
- Tennessee
- Kentucky

10)
- Kansas
- Nebraska
- Iowa
- Minnesota
- Missouri

11)
- Oklahoma
- Arkansas

12)
- Wisconsin
- Indiana
- Illinois
- Michigan

13)
- Montana
- Wyoming
- North Dakota
- South Dakota

14)
- Arizona
- Colorado
- Utah
- New Mexico

15)
- California
- Oregon
- Washington
- Idaho
- Nevada

TABLE 2-2

SUPPLY REGIONS

1) Ohio

2) Northern Appalachia
   - N West Virginia
   - Pennsylvania
   - Maryland

3) Central Appalachia
   - S West Virginia
   - E Kentucky
   - Virginia
   - N Tennessee

4) Southern Appalachia
   - S Tennessee
   - Alabama

5) Illinois Basin
   - W Kentucky
   - Indiana
   - Illinois

6) Central Plains
   - Kansas
   - Missouri
   - Nebraska
   - Iowa

7) Okl /Iowa Bituminous

8) Texas Lignite
   - Texas
   - Louisiana

9) Great Plains Lignite
   - N Dakota
   - Montana

10) Powder River Basin - Montana

11) Powder River Basin - Wyoming

12) Southern Wyoming

13) Uinta Basin
   - N W. Colorado
   - N. Utah

14) Four Corners
   - S Utah
   - S. Colorado

15) San Juan
   - Arizona
   - New Mexico

determined by a mining cost model Coal moves between the supply and demand regions via a transportation matrix, which incorporates rail, slurry pipeline, and barge movements.

Essentially, the model allocates demand among the supply regions such that the combined cost of producing and transporting the coal is minimized For utility plants operating under the revised NSPS, the model will also attempt to minimize scrubbing costs.

2.2 DEMAND

Coal demand is determined exogenously for the model The demand level is determined primarily by: 1) EEA's Coal Fired Utility Data Base, which includes all operating coal-burning power plants and currently planned installations; and 2) EEA's Industrial Fuel Choice Analysis Model, which projects future fuel choices for both existing boilers and new units which the model "builds " Additional estimates are made for export and metallurgical coal demand Demand for each supply region is divided into four categories.

- Compliance coal demand (1.2 pounds SO_2/MMBtu's or less)
- Low sulfur coal demand (above 1.2 pounds SO_2 to 2 0 pounds)
- High sulfur coal demand (above 2.0 pounds SO_2)
- Demand from power plants subject to NSPS II

NSPS II plants will pick the combination of scrubber type and coal type which will minimize total coal production, transportation, and scrubbing costs Scrubbing costs will vary by the choice of technology (dry vs wet scrubbing), and the alkalinity and heat value of the coal being scrubbed

The inclusion of the NSPS II standard and the new dry scrubbing technology are critical to the accuracy of the model. Particularly for the

period after 1985, when most new plants will be subject to NSPS II, these are the factors which will largely determine the distribution of coal demand across sulfur contents and thus the overall shape of the coal market

The demand projection is summarized in Table 2-3

2.3 TRANSPORTATION

The cost of moving coal between any pair of supply and demand regions is determined by a transportation rate matrix The costs in the matrix represent the lowest cost option between the railroads, barge lines or slurry pipelines which may link a supply and demand region. The cost assigned to each transportation link is based on 1979 rates, adjusted to 1985 or 2000 values in order to reflect

1) Anticipated changes in movement patterns, such as increased use of unit trains.
2) Capital investment by railroads made to increase capacity.
3) Federal legislation and regulation, such as the fuel_use tax on barges

Between some pairs of regions, no coal transport is permitted and in other cases minemouth coal consumption is specified (see Table 2-4)

2.4 RESERVE CHARACTERIZATION

Recoverable coal reserves were estimated via a detailed examination of Federal and State geologic studies The model divides coal reserves into 15 supply regions, each of which are subdivided into dozens of "reserve blocks" containing a specified tonnage of coal Each reserve block is characterized by seam thickness, overburden depth, pitch (for underground mines) and maximum stripping ratio and slope (for surface mines).

TABLE 2-3

DEMAND PROJECTIONS IN QUADS

1985

	C	L	H	N	Total
Electric	5 2	2 4	9 2	1.0	17 8
Industrial	1 3	0 7	0 7	---	2 7
Met Coal	1 1	1.1	---	---	2 2
Exports	0 6	0.7	---	---	1 3
TOTAL	8 2	4.9	9.9	1.0	24 0

2000

	C	L	H	N	Total
Electric	4 9	1 1	8 5	15 1	29.6
Industrial	3 0	3 0	3.5	----	9 5
Met Coal	1 3	1 3	---	----	2 6
Exports	0 8	1.0	---	----	1 8
Synthetics	---	2.5	---	----	2 5
TOTAL	10 0	8 9	12.0	15 1	46.0

Implied Growth Rates

	1985	2000	Annual Growth
Electric	17.8	29.6	3 4
Industrial	2 7	9.5	8 7
Met Coal	2 2	2.6	1 1
Exports	1 3	1.8	2.2
Synthetics	0 0	2.5	---
TOTAL	24.0	46.0	4 4

Source: EEA estimates.

Table 2-4

TRANSPORTATION RATES

DEMAND \ SUPPLY	1 OH	2 N WV/PA MD	3 S WV/E KY/VA/N TN	4 AL/S TN	5 W KY/IN/S IL	6 KA/MO/NO/IA	7 OK/IA BITUMINOUS	8 X/LA/AR LIGNITE	9 ND/MT LIGNITE	10 MT	11 WY POWDER RIVER BASIN	12 S WY	13 NW CO/N UT	14 S UT S CO	15 AZ/NM
NEW ENGLAND/NY 1	18 25	13 3[illegible]	20 40	25 20	23 84	27 45	30 47			30 25 S					
MD/NJ/DE 2	[illegible]2 90	7 61	11 34	19 71	21 [illegible]3	27 32	30 34			3[illegible] 00 S					
PA 3	5 90	3 86	12 1[illegible]	16 80	12 77	19 09	22 11			31 32 S					
OH 4	3 78	[illegible] 22	8 20	13 25	7 81	15 01	18 0[illegible]			26 02 S					
VA/NC 5	1[illegible] 70	12 [illegible]	7 34	7 58	14 96	25 22	23 19								
SC/GA/FL 6	1[illegible] [illegible]0	15 1[illegible]	11 03 P	10 [illegible]3 P	1[illegible] 18	20 86	23 32								
AL/MS 7	15 98	[illegible]9 47	16 01	5 43	11 16 B	20 08	[illegible]4 71			30 20	22 38	25 63	24 36		[illegible]
TX/LA 8	20 2[illegible] B	20 38 B	20 10 B	[illegible]2 9[illegible]	14 16 B	17 44	10 02	MM		[illegible]3 93 [illegible]2 6[illegible] P	13 93 12 63 P	16 [illegible]1	15 33		1[illegible] 18 P
TN/KY 9	[illegible]6 [illegible] B	[illegible]5 6[illegible]	15 38	[illegible] 38	[illegible] 5[illegible]	10 99	12 1[illegible]								
[illegible] 10	1[illegible] 43 B	15 47 B	2[illegible] 64 B	17 46	9 68	4 75	13 87			13 11	8 95	10 83	10 98		15 42
OK/AR 11	20 5[illegible] B	23 97 B	23 [illegible]8 B	15 78	15 51	5 65	94	MM		17 16	[illegible]3 01	13 [illegible]	12 08		1[illegible] 56
WI/IN/IL/MI 12	1[illegible] 66	1[illegible] 41	[illegible]3 [illegible]5	13 95	6 72	11 71	1[illegible] [illegible]2			15 30	4 20	16 35	16 35		[illegible]6 [illegible]0
MT/WY/ND/SD 13									MM	MM	MM	MM			
AZ/CO/UT/NM 14													MM	MM	MM
CA/NV/OR/WA/ID 15										22 69	23 68	11 14	12 78		7 [illegible]

See next page for key.

SOURCE. EEA Estimates

KEY TO TRANSPORATION TABLE

(   ) = no movements permitted

B = barge

S = Great Lakes steamship

MM = minemouth consumption

P = slurry pipeline

All other movements are via unit-train

Reserves blocks are further characterized by sulfur content and heat value A mining method is also assigned to each reserve block, depending on its geologic parameters This extremely fine specification of the reserves makes it possible to more accurately represent the quality and production cost of the coal in each supply region, and thus more accurately project where coal will be mined to meet future demand

Summary reserve characteristics are presented in Table 2-5

2 5 MINE MODELS

Production costs for each reserve block are estimated by mine cost models These estimate a minimum acceptable selling price for a ton of coal high enough to recover all costs plus a 15 percent return on investment The mine cost models used include

- o An underground mine model, covering drift, shaft, longwall and room-and-pillar mines of varying sizes The major factor driving the model is productivity, which is adjusted according to geologic conditions, mine size, supply region, and year of the model run Productivity is assumed to increase over time, reflecting the trend of the past two years.
- o A contour mine model applied to Appalachian surface reserves The model costs are a function of a reserve's geologic conditions, and the assumed level of reclamation required.
- o An area mine model, divided into two major subtypes (dragline stripping, and truck and shovel stripping) each further differentiated by the general characterstics of the supply region they are applied to. On the reserve block level, production costs are a function of overburden depth, stripping ratio, and mine size

The advantage of using a variety of models sensitive to several cost factors is that it makes it possible to tailor a model to a reserve block, and so increase the accuracy of the production cost estimate

TABLE 2-5

RESERVES BY MINING METHOD

SUPPLY REGION	SURFACE	UNDERGROUND
1	6,398	22,844
2	6,932	50,819
3	13,250	44,136
4	383	2,727
5	29,148	86,000
6	6,398	4,150
7	752	1,902
8	10,829	--
9	39,059	--
10	33,213	69,200
11	20,664	74,057
12	5,324	8,622
13	2,327	64,508
14	1,596	33,563
15	9,848	204,151

SOURCES see Section 6 7

2.6 SUMMARY OF RESULTS

To date, the model has been run for 1985 and 2000 cases In both instances the model shows similar patterns declines or moderate production growth in high sulfur coal areas, compared to rapid growth in compliance and low sulfur coal regions This illustrates the central importance of Federal regulations and the dry scrubbing technology The heavy demand for compliance coal is from utility plants operating under the original NSPS The low sulfur demand largely represents utilities under NSPS II minimizing their pollution control costs by dry scrubbing low sulfur coal, in fact, this combination is so cost-effective that the model projects very little wet scrubbing of high sulfur coal Another regulatory factor is the Fuel Use Act which, by attaching a cost penalty to the use of oil or gas in new industrial boilers, further encourages demand for low sulfur and compliance coal

The major supply regions to gain from these demand factors are the areas with low sulfur reserves the west generally, and southern and central Appalachia Overall, total production rises from 680 mmt (million tons) in 1976 to 1 092 billion tons in 1985 and 2.145 billion tons in 2000 (see Table 2-6). In all three cases most production is accounted for by surface mining, with 65 percent of the total in 2000. However, the model does show a resurgence of underground mining (primarily drift) in Appalachia.

Marginal prices are not particularly high in 1985 and, with the exception of southern Appalachian compliance coal, do not increase greatly through 2000 (see Table 2-7 and 2-8). This reflects the generally large size of the reserves which can be mined at a low cost.

TABLE 2-6

COAL PRODUCTION
(millions of tons)

			DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
1.	Ohio	1976	17	30	47	-	-	-
		1985	15	26	41	0	6	35
		2000	31	21	52	-	12	39
2	N. Appalachia	1976	88	55	143	-	-	-
		1985	58	27	85	-	36	49
		2000	141	20	162	-	105	57
3	C Appalachia	1976	113	77	190	-	-	-
		1985	128	119	247	128	93	26
		2000	256	144	400	174	180	46
4.	S Appalachia	1976	10	16	26	-	-	-
		1985	20	43	64	11	38	15
		2000	42	53	95	13	60	22
5	Illinois Basin	1976	55	81	136	-	-	-
		1985	4	103	107	-	20	87
		2000	59	108	167	-	79	88
6.	Central Midwest	1976	0	18	18	-	-	-
		1985	0	91	91	-	-	91
		2000	0	113	113	-	-	113
7.	Oklahoma	1976	0	4	4	-	-	-
		1985	0	27	27	0	18	9
		2000	0	29	29	-	18	11

		DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
8. Texas Lignite	1976	0	14	14	-	0	0
	1985	0	62	62	-	-	62
	2000	0	229	229	-	-	229
9. MT/ND Lignite	1976	0	21	21	-	-	-
	1985	0	47	47	-	33	15
	2000	0	103	103	-	62	41
10 Powder River Basin - Montana	1976	0	19	19	-	-	-
	1985	0	318	138	120	18	-
	2000	0	178	178	169	9	-
12 S Wyoming	1976	1	12	13	-	-	-
	1985	0	0	0	0	0	0
	2000	0	0	0	0	0	0
13. Uinta	1976	10	14	24	-	-	-
	1985	63	2	66	55	11	-
	2000	215	29	244	110	134	-
14 4 Corners	1976	0	5	5	-	-	-
	1985	0	34	34	7	27	-
	2000	-	34	34	7	27	-
15 San Juan	1976	1	5	6	-	-	-
	1985	0	35	35	34	1	-
	2000	0	94	94	66	28	-
Appalachia (regions 1-4)	1976	229	178	406	-	-	-
	1985	221	215	436	139	173	125
	2000	470	238	708	187	357	164

		DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
Midwest	1976	55	103	158	-	-	-
(regions 5,6,7)	1985	4	221	225	-	38	187
	2000	59	250	310	-	98	212
Powder River	1976	-	33	33	-	-	-
(regions 10,11)	1985	0	188	188	170	18	-
	2000	0	424	424	269	156	-
Lignite	1976	0	35	35	-	-	-
(regions 8,9)	1985	0	109	109	-	33	77
	2000	0	332	332	-	62	270
Other West	1976	12	36	48	-	-	-
(regions 12 -	1985	63	71	134	96	39	0
15)	2000	215	157	372	183	189	0
TOTAL USA	1976	295	385	680			
	1985	288	804	1,092	405	301	389
	2000	744	1,401	2,145	639	862	646

Note: Numbers may not add due to rounding.

Source: EEA estimates.

TABLE 2-7

Coal Prices in 1985
(constant 1979 dollars)

		Last Mine to Open			Next Mine to Open		
Supply Region	Sulfur Content	Cost Range	Mine Type	$/ton	Cost Range	Mine type	$/ton
1	H	L	C 11131	23.20	Same as last mine to open		
1	L	H	R 21112	28.95	M	R 21322	30 30
2	H	M	R 21111	26 21	Same as last mine to open		
2	L	L	R 21221	28 80	Same as last mine to open		
3	H	H	R 21121	27.81	M	R 11211	28 95
3	L	H	R 21121	27 81	M	R 11211	28 59
3	C	L	C 22131	29 59	L	C 13121	31 40
4	H	L	R 11211	27 40	L	R 11221	27 40
4	L	L	R 11211	27 40	Same as last mine to open		
4	C	H	R 21122	33 46	M	C 12131	34.03
5	H	L	A 21122	21.08	L	A 11133	22 29
5	L	L	R 21311	24 68	Same as last mine to open		
6	H	B	A 11122	16 21	Same as last mine to open		
7	H	B	A 11232	18.56	B	A 11131	18 90
7	L	B	A 21231	18 90	B	R 21111	34 63
8	H	B	A 21123	11 07	Same as last mine to open		
9	H	B	A 21113	5 41	B	A 31113	5 41
9	L	B	A 21113	5 41	Same as last mine to open		

TABLE 2-7 (Continued)

Coal Prices in 1985

		Last Mine to Open			Next Mine to Open		
Supply Region	Sulfur Content	Cost Range	Mine Type	$/ton	Cost Range	Mine Type	$/ton
10	C	B	A 21122	8.38	B	A 21113	8 42
10	L				B	A 21112	8 38
11	C	B	A 31133	7.39	Same as last mine to open		
11	L	B	A 21122	7 36	Same as last mine to open		
12	C	B	None		B	A 31123	24 34
12	L	B	None		B	A 21123	24 34
13	C	B	A 21123	24.33	Same as last mine to open		
13	L	B	L 31331	24.15	Same as last mine to open		
14	C	B	A 31121	12.10	B	A 21132	18.68
14	L	B	A 31122	11 84	B	A 11132	18.68
15	C	B	A 31123	15.14	B	A 11122	15 62
15	L	B	A 31123	15 14	Same as last mine to open		

TABLE 2-8

Coal Prices in 2000
(constant 1979 dollars)

Supply Region	Sulfur Content	Last Mine to Open: Cost Range	Last Mine to Open: Mine Type	Last Mine to Open: $/ton	Next Mine to Open: Cost Range	Next Mine to Open: Mine Type	Next Mine to Open: $/ton
1	H	H	C 11121	22.90	Same as last mine to open		
1	L	L	C 22131	32.93	H	R 21222	34 23
2	H	L	C 22121	26 05	Same as last mine to open		
2	L	H	R 11221	33.38	H	R 21211	33.85
3	H	L	R 21211	31 29	Same as last mine to open		
3	L	L	C 23121	32 24	M	C 12131	33.40
3	C	L	C 23121	32 24	M	C 12131	33 40
4	H	H	C 22121	30 08	H	R 11211	30.91
4	L	H	R 11211	30 91	L	C 12131	31 72
4	C	H	C 12131	38 06	Same as last mine to open		
5	H	L	A 21122	21.60	L	R 21311	22 53
5	L	H	A 21122	25 92	M	A 11131	26.07
6	H	B	A 21122	16 61	B	A 11132	17 95
7	H	B	A 21231	19.47	B	R 21111	31 43
7	L	B	A 21231	19 47	B	R 21111	31 43
8	H	B	A 11121	11 98	B	A 21133	18 61
9	H	B	A 31113	5 62	B	A 11112	5 77
9	L	B	A 21113	5 62	Same as last mine to open		

TABLE 2-8 (Continued)

Coal Prices in 2000

Supply Region	Sulfur Content	Last Mine to Open: Cost Range	Last Mine to Open: Mine Type	Last Mine to Open: $/ton	Next Mine to Open: Cost Range	Next Mine to Open: Mine Type	Next Mine to Open: $/ton
10	C	B	A 31123	8.81	B	R 31311	43 11
10	L	B	A 31123	8 81	Same as last mine to open		
11	C	B	A 31113	7 73	Same as last mine to open		
11	L	B	A 21112	7 70	Same as last mine to open		
12	C		None		B	A 31123	25 78
12	L		None		B	A 21123	25 78
13	C	B	L 21331	25 85	B	A 11122	26 80
13	L	B	L 21331	25 85	Same as last mine to open		
14	C	B	A 31121	12 54	B	A 21132	19 38
14	L	B	A 31122	12.30	B	A 11132	19 38
15	C	B	A 21122	16.22	Same as last mine to open		
15	L	B	A 31123	15 74	Same as last mine to open		

KEY TO TABLES 2-7 AND 2-8

Sulfur Content

H = high (>2 0 lbs. SO_2/mmbtu)

L = low (>1.2 to 2 0 lbs. SO_2/mmbtu)

C = compliance (1.2 lbs. SO_2/mmbtu or less)

Cost Range (see Section 7 6)

H = High

L = Low

M = Medium

Last Mine to Open — The last mine type projected by the model to open in a supply region for each supply content Equivalent to the marginal mine.

Next Mine to Open — The source of production if demand were to increase by one unit.

Mine Type Code

Surface Mines.

- C = contour mines
- A = area mines

- numeric code (for values see below)
  - first digit = seam thickness
  - second digit = pitch
  - third digit = slope
  - fourth digit = stripping ratio
  - fifth digit = block size

Deep Mines

- R = Room and Pillar
- L = Longwall

- numeric code (for values see below)
  - first digit = seam thickness
  - second digit = pitch
  - third digit = block size
  - fourth digit = overburden depth
  - fifth digit = drift or shaft

<u>Values for Mine Codes</u>

- Seam Thickness (1) = 28 to 41 inches
  (2) = 42 to 119 inches
  (3) = > 119 inches

- Pitch (1) = 0 to 10°
  (2) = 11° to 30°
  (3) = >J 30°

- Slope: (1) = 0 to 10°
  (2) = 11° to 20°
  (3) = > 20° to 30°

- Stripping Ratio (1) = 5 1
  (2) = 10 1
  (3) = 20.1

- Overburden Depth (1) = 0 to 500 Feet
  (2) = > 500 to 2000 feet
  (3) = > 2000 feet

- Drift or Shaft. (1) = Drift
  (2) = Shaft

- Block Size (1) = 6 mmt (million tons)
  (2) = 20 mmt
  (3) = 40 mmt
  (4) = 60 mmt
  (5) = 150 mmt

3 INTRODUCTION TO THE REPORT

As part of its investigation of advanced underground coal extraction systems, the Jet Propulsion Laboratory contracted with Energy and Environmental Analysis, Inc. (EEA) for a projection of coal supply and associated mining conditions in the years 1985 and 2000. This report documents the model which was developed to provide the forecasts and presents model results. The documentation includes the coal supply curves produced by the model, the programming for the mining cost models, and an accompanying user's manual In addition, the underlying assumptions behind the demand, transportation, coal reserve characterization, and mining cost components of the model are presented. The model results present coal production patterns and marginal production prices, differentiated by mining method and coal sulfur content

The remainder of the report is divided into the following sections

- Section 4 describes the basic model structure
- Sections 5, 6, 7, and 8 describe, respectively, the demand, reserve characterization, mining cost, and transportation components of the model. In each case the underlying assumptions and methodology used to develop the component are described. In the case of the mining cost section, all of the inputs to the mining cost model are also presented.
- Section 9 presents model results for 1985 and 2000
- Appendix A outlines the structure of the linear programming model used for this study
- Appendix B contains the users guide to the coal supply curve programs
- Appendix C contains detail on geometric calculations used in the coal reserve calculation

4. MODEL OVERVIEW AND LIMITS ON THE ANALYSIS

This section presents an overview of how the EEA coal model functions, and a discussion of limits on the analysis The section is divided into three parts·

- o A summary description of the model and its components
- o A brief description of the model outputs
- o The discussion of limits on the analysis

4 1 SUMMARY DESCRIPTION OF THE MODEL AND ITS COMPONENTS

The EEA coal model is designed to project future coal production patterns, mining methods and production prices, given an exogenously determined level of demand. The model is of the linear programming (L-P) type* and is designed to seek a market equilibrium solution (i e., demand and supply perfectly matched) in which all costs are minimized The model consists of the following components.

4.1.1 Coal Demand

Demand is established exogenously for the model, and covers the major demand sectors utilities, industrial boilers, metallurgical coal demand, synthetic fuels, and exports. Demand is split among 15 demand regions covering the 48 conterminous states (see Table 4-1), and between four coal sulfur categories. These are·

- o Compliance coal (no more than 1 2 pounds of SO_2/mmbtu)
- o Low sulfur coal (more than 1.2 and up to 2.0 pounds SO_2)
- o High sulfur coal (above 2.0 pounds SO_2)
- o A sulfur-unspecified category (see Section 4.1.5)

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* The formal structure of the L-P is presented in Appendix A.

TABLE 4-1

DEMAND REGIONS

Region	States	Region	States	
1)	o New England o New York	10)	o Kansas o Nebraska o Iowa	o Minnesota o Missouri
2)	o New Jersey o Delaware o Maryland	11)	o Oklahoma o Arkansas	
3)	o Pennsylvania	12)	o Wisconsin o Indiana o Illinois	o Michigan
4)	o Ohio	13)	o Montana o Wyoming o North Dakota	o South Dakota
5)	o Virginia o North Carolina	14)	o Arizona o Colorado o Utah	o New Mexico
6)	o South Carolina o Georgia o Florida	15)	o California o Oregon o Washington	o Idaho o Nevada
7)	o Alabama o Mississippi			
8)	o Texas o Louisiana			
9)	o Tennessee o Kentucky			

4 1.2 Coal Reserve Characterization

Recoverable coal reserves in the 48 conterminous states are divided between 15 supply regions covering the major bituminous, sub-bituminous, and lignite coal reserves (see Table 4-2) Within each supply region the reserves are divided into dozens of reserve categories, each with a specified tonnage of coal The reserve categories are differentiated by coal heat value and sulfur content, and by a variety of geologic parameters These include

- o Seam thickness
- o Block size (the amount of coal in a reserve which can be allocated to a single mine)
- o Pitch and whether the reserve is drift or shaft-mineable (for underground mines)
- o Stripping ratio and slope (for surface mines)

As the above list implies, a mining method is also assigned to each reserve block.

4 1 3 Mine Cost Models

The mine cost models assign a production price to each reserve category (i.e., the production price for a unit of coal mined from the reserve). This price, also referred to as the minimum acceptable selling price (MASP), is a price high enough to recover all costs, plus a 15 percent return on investment. The following basic mine costing models were used:

- o An underground mining model, including room and pillar and longwall mining
- o A contour mine model for Appalachian surface reserves
- o An area mine model for western surface reserves

As noted above, the applicable mining method for each reserve is specified by the reserve characterization Mining costs vary according to

TABLE 4-2

SUPPLY REGIONS

1) Ohio

2) Northern Appalachia
   - N. West Virginia
   - Pennsylvania
   - Maryland

3) Central Appalachia
   - S. West Virginia
   - E Kentucky
   - Virginia
   - N Tennessee

4) Southern Appalachia
   - S. Tennessee
   - Alabama

5) Illinois Basin
   - W Kentucky
   - Indiana
   - Illinois

6) Central Plains
   - Kansas
   - Missouri
   - Nebraska
   - Iowa

7) Okl /Iowa Bituminous

8) Texas Lignite
   - Texas
   - Louisiana

9) Great Plains Lignite
   - N. Dakota
   - Montana

10) Powder River Basin - Montana

11) Powder River Basin - Wyoming

12) Southern Wyoming

13) Uinta Basin
   - N W Colorado
   - N Utah

14) Four Corners
   - S Utah
   - S Colorado

15) San Juan
   - Arizona
   - New Mexico

each reserve's geologic characteristics, the year of the projection, and the supply region in which the reserve is located. Note that by assigning a production price to each reserve, the model creates supply curves for each supply region. These curves show how much coal of a particular sulfur content is available at a given MASP.

4 1 4 Transportation

A matrix of transportation costs specifies the price for moving coal from a supply to a demand region The costs used in the model represents the lowest between the available alternatives (barge, rail, or slurry pipeline) In cases where coal movements are considered prohibitively expensive or implausible (such as a coal movement from Appalachian supply regions to the West Coast demand region) coal transport is prohibited In other cases, minemouth coal consumption is specified

4 1 5 Model Solution Criteria

As noted, the model is of the L-P form It will seek a market equilibrium solution in which sufficient coal is produced to fill all demand at the minimum possible cost. Specifically, it will allocate demand across the supply regions such that total production and transportation costs are minimized.

A special case is the portion of demand which falls into the unspecified sulfur content category This represents demand from new utility plants which must comply with the revised New Source Performance Standard (NSPS-II) for utility emissions of SO_2. The standard essentially requires that:

- Plants burning coal with a sulfur content equal to or less than 2.0 pounds SO_2/MMBtu must achieve 70 percent removal. This can be accomplished via either of the two available desulfurization technologies, wet or dry scrubbing.

- o Plants burning coal with more than 2 pounds SO_2 must achieve a level of removal set by a sliding scale ranging from 70 to 90 percent Wet scrubbing is used in this case

For most components of demand, the sulfur content is either known (as for existing power plants) or can be reasonably estimated This is not true for demand from NSPS-II plants, since they can juggle the costs of two different scrubbing technologies and three sulfur types to reach the most economical combination Accordingly, the model is used to determine what kind of coal NSPS-II demand is filled with, such that total production, transportation, <u>and</u> scrubbing costs are minimized

4.2 MODEL OUTPUTS

The model generates a large variety of outputs for a production projection The most important outputs from the perspective of the JPL project are briefly discussed below.

4.2 1 Marginal Price

The marginal price is the MASP for the last unit of coal produced An individual MASP is established for each sulfur content in each supply region (i e., for each supply curve). The marginal price is particularly significant for two reasons. First, it establishes the minimum selling price for all coal of the same sulfur content in a supply region Second, it indicates the cost ceiling a new mining technology will have to beat in order to be cost competitive.

4.2.2 Production Method

The model indicates the split between mining methods in each supply area. It also indicates the breakdown in production between reserves with broadly different geologic characteristics For example, the percent of area mine production from high and low stripping ratio reserves is presented for each supply region.

4.2.3 Aggregate Production Totals

The model indicates how much coal is produced in each region, differentiated by sulfur content It also indicates the supply regions from which each demand region is drawing its coal and, for the case of NSPS-II demand, what kind of coal is being produced to fill it and which scrubbing method is being used.

4 3 LIMITS ON THE ANALYSIS

In interpreting the results from the model, three major cautions must be kept in mind First, the model is built upon assumptions about the future which could be proven wrong For example, the model assumes that mining technology will remain essentially unchanged through the rest of the century If a new, very low-cost mining technology were to be developed and widely implemented, it would have impacts on future coal demand and production patterns unforeseen by the model.

Second, the model assumes a perfectly rational world, in which all producers and consumers will take the steps necessary to minimize their costs and precisely match demand with production While this may be approximately true over the long term, at a given moment supply and demand are unlikely to be in perfect balance, and, due to error, lack of information or other factors, it is fair to assume that costs will never be minimized. For these reasons alone the model can be expected to deviate somewhat from reality

Finally, the model is, of course, only a rough approximation of reality It uses detailed but nevertheless abstracted estimates of demand, coal reserves, mining costs and transportation costs Accordingly, it produces an abstracted picture of the future, one which will be most accurate in terms of the general trends and characteristics it forecasts for the coal industry.

5 DEMAND

5.1 INTRODUCTION

The purpose of the EEA coal model is to determine future coal supply and price characteristics for a given demand scenario. In order to forecast coal demand in the years 1985 and 2000, two of coal's markets, which together accounted for 83% of coal demand in 1978, were examined in detail the electric utility market and the industrial coal market The electric utility projection relies on two assumptions· 1) in the short term (1985), utility coal demand is estimated accurately by relying primarily on the utilities' own projections of coal requirements as interpreted using EEA's utility demand data base; and 2) by the year 2000, all electricity not generated by nuclear power plants will be coal generated. It is further assumed that nuclear expansion will be limited by public concern over its safety, resulting in fewer nuclear power plants than economics alone might dictate.

EEA's Industrial Fuel Choice Analysis Model (IFCAM) was used to develop the industrial demand projection. IFCAM forecasts are based on assumptions of industrial growth rates, tax structure, energy and environmental regulation, and relative fuel prices. The model provided regional forecasts of coal demand by the industrial section for 1985 and a 1995 estimate, which was extrapolated to 2000

Coal's other markets -- metallurgical coal and exports -- are small compared to the combined utility and industrial coal market, and proportionally less effort went into forecasting demand in these sections.

The EEA coal model does not directly simulate the interaction between supply and demand, but rather assumes that supply responds once to the demand level and reaches equilibrium by establishing prices. This

limitation can be partially circumvented by developing several demand scenarios Since this is beyond the scope of the project, one demand forecast is made This forecast represents a best estimate of coal demand rather than a high, low, or intermediate projection

By using only one demand estimate that is not endogenously determined, the model assumes that coal demand is unresponsive to coal prices While this is obviously a simplification, coal demand is probably as dependent on a list of other unknown factors, such as the cost of alternative fuels, the future of nuclear power, environmental and energy regulations, and the willingness of the U S to switch from the cleaner, more convenient, but scarcer fossil fuels to more abundant yet more troublesome coal Therefore, the demand projections to 1985 and 2000 assume that coal will be significantly less expensive than other fossil fuels and, in the long run, will significantly penetrate major markets

5 2 MARKETS FOR COAL   AN OVERVIEW

The structural change in the energy economy due to the current oil situation renders the use of trend projection an obsolete forecasting tool. Nevertheless, before proceeding with the forecast methodology discussion, an examination of historical trends in the coal market will provide some useful perspective Also discussed are factors likely to influence future demand in each of coal's markets Table 5-1 shows historical coal demand by sector.

5.2.1 Utility Coal Market

5.2.1 1 Historical

While coal consumption in every other end-use sector has declined steadily over the past 30 years, electric utility coal consumption has quintupled As a result, the utility sector, which consumed less than 20 percent of the coal used in 1948, now represents nearly 80 percent of the domestic

coal market. As Table 5-1 shows, coke plants, industrial boilers, and the transportation sector each consumed more coal than the utilities in 1948 In the years since, transportation, residential, and commercial coal consumption have dwindled to practically nothing with the demise of the steam locomotive and the increased availability of natural gas and petroleum for space heating Industrial consumption has dropped by nearly half Utility consumption, however, has risen from 95 million tons in 1948 to 480 million tons in 1978. Total coal use in that same period has risen only 100 milion tons--from 570 million tons to 618 million tons per year. In fact, coal use actually fell throughout the 1950's and finally began to rise again in the early 1960's because of increased coal use by the utility sector

At the same time that the utility sector's role in the coal market has expanded, coal's role in electricity production has actually decreased in terms of percentage of total generation Though coal use by utilities grew fivefold in 30 years, electricity production has grown nearly eightfold. From 283 billion KWh in 1948 to over 2200 billion KWh in 1978, electricity production grew at an average annual rate of 7 percent For much of the 1950's and 1960's steam generation was responsible for more than 80 percent of all electricity generation In the last decade with the advent of nuclear power, conventional steam's role has diminished somewhat. Conventional steam generators today produce about 70 percent of all electricity produced by utilities, just as they did in 1948

Coal once fueled more than three quarters of all conventional steam electricity generation. Its share has now dropped to about 60 percent Both oil and natural gas have fueled increasingly large shares of such generation since 1950. Petroleum use by utilities has grown at an average rate of 11 percent per year and natural gas at 8 percent per year, compared to coal's 7 percent per annum rate Natural gas use grew most quickly in the 1950's and 1960's. With increasing availability, its reliability as a power plant fuel improved and its price was competitive with coal In

TABLE 5-1 HISTORICAL COAL DEMAND BY END USE 1948-1978
(millions of short tons)

Year	Electric Utility	Industrial	Metallurgical	Transportation	Residential & Commercial	Exports
1948	95.6	132.8	107.3	97.4	86.8	28.0
1950	88.3	114.7	103.8	63.0	84.4	25.5
1955	140.6	105.3	107.4	17.2	53.0	51.3
1960	173.8	92.1	81.0	3.0	30.4	36.5
1965	242.6	101.9	94.8	0.7	19.0	50.2
1970	318.3	88.3	96.0	0.3	12.1	70.9
1971	325.7	74.1	82.8	0.3	11.4	56.6
1972	350.2	71.9	87.3	0.2	8.7	56.0
1973	387.8	67.2	93.6	0.1	8.2	52.9
1974	390.3	64.0	89.7	0.1	8.8	59.9
1975	404.5	62.5	83.3	0.5	7.3	65.7
1976	447.0	60.5	84.3	0.5	6.9	59.4
1977	475.7	60.4	77.4	0.5	7.0	53.7
1978	480.1	58.9	71.1	0.5	7.9	41.7

Source Energy Information Administration, Synopsis of Energy Facts and Projections, 1979

the 1970's, natural gas use by utilities dropped with the recognition of gas as a scarce resource Oil use, on the other hand, grew slowly in the 1950's and 1960's because the cost of oil was more than twice the cost of gas on a per Btu basis. Oil's most significant advance in market share came during the period 1968-73 when utilities increased their use by nearly 25 percent per year During this period coal began a decade of steady price increases and oil prices remained, for this short period, relatively stable. More importantly, oil was a good substitute for scarce natural gas and "dirty" coal From 1968 to 1973 many utilities switched boilers to oil because it was less expensive to burn The 1973 Arab oil embargo, the recession that followed, and the dramatic oil price increases of the last seven years have made oil considerably less attractive as a utility fuel. Nevertheless, petroleum still fuels about 15 percent of U.S electricity production The nuclear share has jumped to about 7 5 percent Coal is responsible for about 50 percent, a share that has been in a slow decline for years but one that will likely grow in the future

While numerous factors have influenced the fuel split of the electric utility sector, only one factor has driven steady increases in total fuel consumption a 7.3 percent average annual growth rate in electricity demand since 1948. In the 1950's, demand grew most rapidly, an average of 9 percent per annum. In the 1960's, demand grew at a rate equal to the 30 year average of 7.3 percent annually In the last decade demand growth has slowed considerably--to an average of about 5 percent--and even less during the past five years.

5 2 1.2 Market Outlook

The utility sector will probably remain coal's biggest customer for some time to come. For the next ten years, utilities have planned enough coal-fired capacity to add 425 million tons to current coal consumption. Alone it would increase total coal consumption by over half and it would

double current utility consumption Utility consumption may not grow as quickly if electricity demand continues to grow more slowly than predicted, as has been the case in recent years But its share will undoubtedly remain substantial. Only one other utility alternative, nuclear power, is assuming an increasing share of total electricity generation. Other coal markets, which have suffered years of decline, are on the verge of improving. But the utility sector's mammoth share will still dwarf these markets Two factors will determine utility coal demand· future electricity demand growth rates and the rate of penetration or removal of alternatives from the utility market

Electricity demand growth rates, which were once reliably predicted solely through extrapolation of historical data, have defied easy prediction in the past several years Actual growth rates have been consistently lower than projected rates. Many factors have confounded accurate projections of demand The price and availability of other substitute energy sources and more efficient energy use in all sectors have contributed to the reduction in demand growth. These factors and others are likely to continue to have an impact on future growth rates For instance, natural gas deregulation and the incremental pricing scheme dictated by the Natural Gas Policy Act of 1978 should make more gas available for residential space heating, which in turn could slow residential electricity demand Conservation efforts will also continue to slow electricity demand but it is difficult to predict the degree Of course, electricity demand will still be fundamentally tied to such factors as GNP and population growth. For instance, any serious recession would certainly slow electricity demand growth. Nevertheless, the factors that determine demand growth have become more complex, and projections of future electricity demand even for the near-term are less reliable than before

Beyond electricity demand growth, the other important factor to consider in evaluating coal's future in the utility sector is the role of other

utility fuels Oil and gas, which had been eroding coal's share of the market for years, are on the way out as utility boiler fuels. Gas consumption by utilities has been declining for several years and should continue to do so because new boilers are forbidden from burning gas by the Power plant and Industrial Fuel Use Act (PIFUA) Oil use is also forbidden in new boilers, but its use may continue to rise for several more years while previously planned utility boilers come on line However, oil use may not reach projected levels if DOE conversion efforts are successful. With authority under PIFUA, DOE may prohibit power plant boilers from burning oil or gas if they have or had at one time the capability of burning alternative fuels, mainly coal. With President Carter's call to cut utility oil consumption by half by 1990, DOE is focusing efforts on utility prohibition orders Although previous fuel conversion programs were far from successful, future efforts will be aided by spiralling crude oil prices, uncertain oil supply, and increased coordination with the Environmental Protection Agency

Nuclear power had been projected to assume the biggest increase in market share as oil and gas use drop Current utility projections indicate that nuclear's share of total generation would double in the next decade to increase its share to over one quarter of all electricity generation. However, a cloud of uncertainty has settled over this forecast with the accident at Three Mile Island and the continued inability of all involved to find an adequate long-term solution to radioactive waste disposal No moratorium on construction of nuclear power plants is likely to occur because severe power shortages would certainly result in some areas of the country in the next decade, replacement capacity could not be built in time However, it is likely that cautionary measures will continue to slow the growth of nuclear power and a further shift to coal power might occur despite its environmental drawbacks. The regulatory issues constraining the use of nuclear power, the high cost of money in recent years, and the difficulty some utilities have had in keeping capacity utilization high, have all made

the adjusted price of nuclear power equal to or higher than that of coal.

The pollution control costs associated with coal burning represent its major demerit as a utility fuel, but it is increasingly being seen as the only fuel on which utilities can depend Huge domestic coal reserves exist and after the oil and gas price increases of the 1970's, coal is much cheaper than the alternatives on a Btu basis Major price increases are not likely to occur in the near future because the coal industry has over 100 million tons of excess production capacity The real price of coal has declined over the past three years Rail rates pushed the current dollar cost of delivered coal higher in some regions for a period, but this trend appears to be slowing Though planning and construction periods for coal-fired plants have been prolonged by permitting and other institutional delays, nuclear plants experience even greater delays In addition, the costs of nuclear power generation are no longer viewed as far below those of coal-fired power. Recent studies have even shown near equality of total costs in some cases Thus, utilities increasingly see coal as the fuel of last resort

5 2 2 Industrial Coal Market

In 1978, 58 9 million tons of coal were consumed by the industrial sector This is approximately 7 5% of total U S coal demand

Fossil fuels are consumed by the industrial section in three broad classes of uses boilers (to provide steam or hot water), process heaters (such as kilns, furnaces, and smelters); and as raw materials feedstock Table 5-2 illustrates the breakdown of the industrial sector's consumption of oil and gas by functional use and industry groups A total of 640 million coal ton equivalents of oil and gas were consumed by the industry in 1974. Industrial use of coal in 1974 was 64 million tons, or less than 10% of the total industrial energy demand

TABLE 5-2 OIL AND GAS CONSUMPTION BY FUNCTIONAL USE IN 1974[a/]
(quads)

SIC Code[b/]	Major Group	Boiler[c/]	Raw Materials	Process Equipment	Other[d/]	Total	% of Total Industrial Fuel Use
20	Food	0.40	-----	0 10	0.10	0.60	4
22	Textiles	0 13	-----	0 03	----	0 16	1
26	Paper	0 71	-----	0.15	0 13	0 99	7
28	Chemicals	1.10	2 30	0.50	0 28	4 18	29
29	Petroleum	0 63	-----	2.20	0 05	2 88	20
32	Stone, Clay and Glass	0 02	-----	0 80	----	0 82	6
33	Primary Metals[f/]	0 30	0 10	1 10	0 20	1.70	12
All Other Industry[g/]		1 63	-----	1.64	----	3 27	21
Total Industry		4 92	2 40	6.52	0.76	14.60[e/]	100

a/ Includes LPG, feedstocks, and refinery (still) gas

b/ Standard Industrial Classification

c/ Process steam production and electricity generation.

d/ Space heating and cooling, lighting, coke production, machine drive, other uses not specified by kind, and data not elsewhere classified

e/ Fuel use is the adjusted ECDB oil and gas with feedstocks, raw materials, and byproduct fuels added back in to illustrate the major functional uses

f/ Includes Steel and Aluminum

g/ Functional uses of oil and gas by other industries were derived from functional shares of total energy used by all manufacturing sectors (EEA, Energy Consumption Data Base, Volume 1 - Summary Document, prepared for EEA, June, 1977)

Coal use by the industrial sector has declined significantly over the last three decades (see Table 5-3). Industrial coal use went from about 132.8 million short tons in 1948 to 58 9 million tons in 1978. This represents an average decline of 4 1% per year Coal's share of industrial energy consumption fell from 34% to 8% over the same period as industrial users switched to oil and gas

The move from coal to oil and gas was due to two factors First, coal required extra capital for handling and burning which made the cost of burning coal much higher than the cost of burning oil or gas Second, environmental regulations discouraged the use of coal and contributed to the growing use of oil and gas

Industrial coal use is likely to grow over the next three decades due to rising costs of oil and gas Coal currently has less than one-fifth of the industrial boiler fuel market Since 90 percent of existing industrial boilers are not designed to burn coal, the potential for increased coal use depends on the rate at which firms install new boilers or convert existing (coal capable) boilers. This, in turn, depends on the economic attractiveness of burning coal based on relative fuel prices and capital costs Since the capital cost of a coal fired boiler can be from three to five times the cost of oil or gas-fired boilers, the price difference in the fuel costs may not be enough to encourage a switch to coal.

The government encourages industrial coal use through regulations and tax incentives. For example, the Power Plant and Industrial Fuel Act of 1978 requires new large industrial boilers to be coal-fired The act further mandates that existing coal-capable boilers may be ordered to use coal-oil or other fuel mixtures 1/ An investment tax credit of 20% may be taken when applied to coal investment in coal-fired boilers. While this credit is scheduled to be returned to the standard 10% level in 1983, it currently provides additional incentive to invest in coal burning equipment.

TABLE 5-3

INDUSTRIAL DEMAND FOR FOSSIL FUELS

(millions of coal tons equivalent)*

Year	Oil	Gas	Coal
1948	115 1	140 0	132.8
1950	120 7	158.0	114.7
1955	157.8	209.1	105.3
1960	180 1	265.7	92 1
1965	212 6	327 4	101 9
1970	253 5	426 0	88 3
1971	256 3	441 6	74 1
1972	286.9	443 5	71 9
1973	300 8	469 2	67 2
1974	294.3	449 9	64 0
1975	279 5	385 4	62 5
1976	315.7	396 0	60 5
1977	350 0	390 0	60.4
1978	355.6	374 8	58 9

* Conversion factors $92\ 85 \times 10^6$ for oil
$46\ 05 \times 10^6$ for gas

Source. Energy Information Administration, Synopsis of Energy Facts and Projections, 1979

The higher prices for oil and gas, uncertainties about future availability of these fuels, and government intervention will combine to reverse the decline in industrial coal use. Nevertheless, the industrial coal market will remain small compared to the utility coal market

5.2 3 The Metallurgical Coal Market

Metallurgical coal is used in the manufacture of iron and steel, and therefore demand for this type of coal is welded to the fate of the volatile steel industry. Metallurgical-grade coal is heated to 2000°F to form coke, which provides the main fuel for the blast furnaces used in steel manufacture Demand for met coal stood at 71.1 million short tons in 1974, significantly below its recent peak of 93.6 million tons during the 1973 steel industry boom (see Table 5-1)

Since metallurgical coal demand is chiefly a function of steel demand, future met coal demand depends on whether the steel industry can recover by making the necessary investment required to modernize facilities It remains to be seen whether the steel industry will overcome competition from Japanese and European steel producers to improve its market share

Another factor affecting coke demand is the "coke efficiency" of the steel industry The U.S steel industry required approximately 860 tons of coke to make one ton of iron in 1956 This "coke ratio" has fallen to .611 in 1975 and further declines are possible. A Bureau of Mines study projects a further 10% decline by 1985. The decline in the coke ratio and the future of the steel industry will be the biggest determinants of future metallurgical coal demand

Metallurgical coal is also exported, primarily to Japan and Western Europe. U.S. exporters compete primarily with Australian and Canadian met coal producers (who currently enjoy a production cost advantage) These foreign markets will continue to provide a substantial market for

met coal if U.S exports can remain price competitive with Australia and Canadian exports

5 2 4 Coal Exports

Exports of bituminous coal totaled approximately 41 million tons in 1978, about 8 percent of domestic production [2/] Japan and Canada made up most of the export market, buying more than 60% of all exported coal

The bulk of exported coal has traditionally been metallurgical coal, but the fledgling steam coal market is expected to boom due to the world oil situation The 2 million tons of steam coal exported in 1979 is likely to more than triple in 1980, then triple again by 1985 Some observers are forecasting that steam coal exports could reach 80 million tons by 1990.

The Japanese market is likely to show the most growth The Japanese plan to expand steam coal imports from the current 1 million tons to 54 million tons per year by 1990 The U S will compete with cheaper Australian coal for this market Europe, too, will be importing steam coal to replace foreign oil as well as increasingly expensive European coal. Coal market observers predict that U S. coal could capture half the European coal market (projected to be 140 million tons a year) by 1990. Competition for this market will come from Canada, China, India, and Columbia, but the U.S. may have a price advantage due to superior extraction technologies and huge production capacity [3/]

5.2.5 Synthetic Fuel Coal Demand

The Federal government has undertaken a program to establish a synthetic fuels industry. Because most of the technologies are untested commercially, it is difficult to project how large the synthetic fuels industry will be by the year 2000 and what the resulting coal demand will be However, it is unlikely that the synthetic fuels industry will account for a major portion of coal demand in 2000.

There are several technologies available for converting coal into gaseous and liquid fuels.

- Low-Btu Gasification - results in an easily cleaned, low quality industrial and utility fuel Its low heat value makes transporting the gas uneconomical and it is used on-site.

- Medium-Btu Gasification - gas produced is a suitable industrial fuel and chemical feedstock, but not a substitute for pipeline quality gas Transportation over great distances is uneconomical.

- High-Btu Gasification - gas produced is compatible with natural gas· it can be mixed or substituted for natural gas in existing pipeline systems

- Synthetic Crude Oil - coal-based liquid similar to poor grade crude oil Can be used as a chemical feedstock or as a transportation fuel.

- Methanol - may be used mainly as a substitute for gasoline in the transportation sector.

The development of a synthetic fuels industry will mean increased coal demand of between 80 and 300 million tons annually by the year 2000. Western sub-bituminous coal has properties which will make it ideal for gasification and liquefaction technologies and the syn-fuels industry will probably increase demand for this coal. Also, since most of the syn-fuels products will replace oil and gas rather than coal, the overall coal market will be expanded [4/]

5.3 DEMAND REGIONS

The U.S. has been divided into 15 demand regions for the purposes of the model The selection of demand regions is important because it determines the accuracy of transportation costs. The model relies on a transportation cost matrix which assigns a single cost of coal movement from each supply region to each demand region. Having more demand regions, each of a smaller size, allows a more concise determination of coal transportation costs from each supply sector However, as the number of demand

regions increases, so does the complexity of the model It is therefore necessary to limit demand regions to a number that is reasonably handled by the model At the same time, there cannot be so few demand regions that transportation costs cannot be estimated with some reasonable degree of certainty

Contiguous states are aggregated into demand regions by considering the states' location relative to coal supply regions There are two general situations either a collection of states is likely to be supplied by only one supply region or the states are located between two or more competing supply regions. In the former case, since transportation costs from the supply region to each of the states within the area will be roughly the same, those states can be grouped together without risking any reduction in model accuracy In the latter case, however, more care must be given to grouping the states When there are competing supply regions, transportation costs (which are estimated based on the supply and demand regions) become a critical factor

The demand regions are listed below with the justification for aggregation

1. <u>New England</u> (including New York)
   - All coal flowing into New England will be coming from Appalachia
   - Rail rates will be similar from supply regions to New England
2. <u>Maryland, New Jersey, Delaware</u>
   - The region is geographically small, so rail rates will not be very significant from the supply regions to these states.
3. <u>Ohio</u>
   - Coal supplied primarily by Ohio and Pennsylvania mines.
4. <u>Pennsylvania</u>
   - Coal supplied by Pennsylvania mines.

5 Virginia, North Carolina, West Virginia

- o Most coal will be supplied from within the region.
- o No supply region will compete with coal from these states
- o Rail rates from other supply regions will not vary.

6 South Carolina, Georgia, Florida

- o Coal will be supplied by the Appalachian region.
- o Similar rail rates apply to all points in the demand region, with the exception of Florida.
- o Since most coal going to Florida is from Appalachia, grouping Florida with the other two states will not result in inaccurate coal flows

7. Alabama, Mississippi

- o Similar rail rates apply to all points in the demand region
- o The coal will be supplied by the Alabama/Southern Tennessee coal region

8. Texas, Louisiana

- o Will be supplied by Western coal, Texas lignite.
- o Rail tariffs vary, but only within Texas However, Texas will not be getting coal from Alabama, so dividing Texas would not add to the model accuracy.

9 Tennessee, Kentucky

- o Coal internally supplied by these states.
- o Similar rail rates apply to all points in the demand region.

10. Kansas, Nebraska, Iowa, Missouri, Minnesota

- o While this is a geographically large demand region, population centers (demand centers) are generally east. Therefore, rail tariffs will not be misstated

11. Oklahoma, Arkansas

- o Similar rail rates apply for supply regions to all points in the demand region.
- o All coal will come from the Western supply regions.

12 Wisconsin, Illinois, Indiana, Michigan

- o Demand is centralized in the South Lake Michigan area
- o Therefore, similar rail rates apply from supply regions to all points in the demand region

13 Montana, Wyoming, North Dakota, South Dakota

- o Coal will be internally supplied.
- o There is a significant amount of minemouth generation in these states making transportation costs zero

14. Arizona, Colorado, Utah, New Mexico

- o Coal is internally supplied

15 California, Nevada, Oregon, Washington, Idaho

- o While this is a large geographical area, these states form a crescent around the Utah and Wyoming supply regions
- o Therefore, there will be only small differences between competitive rail tariffs from Utah and Wyoming

5 4 ELECTRIC UTILITY DEMAND IN 1985

Through 1985, utility fuel use is best projected on the basis of announced utility plans Because coal-fired power plants require a minimum of eight years from the planning stage to start up and nuclear plants require an even longer lead time, utility plans through at least the next five years can reliably be expected to become reality--with one exception. If electricity demand growth rates continue to fall below projected rates, planned projects may be delayed somewhat and associated fuel consumption may not occur While EEA believes that electricity demand will not grow at the five percent annual rate that utilities

project through 1985, we do not believe that coal demand will suffer significantly as a result Thus, EEA relies primarily on utility projections to predict 1985 utility coal demand

5 4 1 Methodology

To predict 1985 coal demand, EEA utilized its own utility coal demand data base which contains historical plant-specified data on coal consumption as well as known characteristics of planned power plants The existing power plant data base contains the following relevant data for each power plant the tonnage of coal consumed in 1978, the average heat and sulfur content of that coal, whether the plant has SO_2 scrubbers or not, and the SO_2 emission limits. The information from the new power plant data base used to project 1985 demand included capacity, location, date due on line, SO_2 compliance strategy (scrubber or no scrubber), and SO_2 emission limit As further described below, the power plant-specific data was aggregated by region to develop 1985 coal demand characteristics

To determine 1985 demand, EEA assumed the existing demand component would remain essentially unchanged and new demand for coal would occur as projected power plants arrive on line Both assumptions require further justification

In actuality, coal demand from existing coal-fired power plants would decrease to some extent over the next seven years Capacity utilization factors would decrease for some plants, especially the older ones, because new plants produce electricity more cheaply and, as they come on line, would phase out older plants On the other hand, EEA believes that oil and gas prices will encourage accelerated retirement of oil- and gas-fired boilers and possibly induce utilities to prolong the lives of their coal-fired power plants, which would be more economical by comparison. To some extent this phenomenon is already occurring as illustrated by the wheeling of power by coal-fired utilities to oil-

dependent utilities in order to displace oil consumption The equivalent of 20 million tons of coal per year is currently being burned to displace oil--an extraordinary increase from even a year ago. However, the quantitative impact of this effect in 1985 cannot be easily predicted

One other demand component can be expected to more than offset any decrease in coal demand from existing plants: conversion of boilers currently firing oil or gas to coal-firing. Current DOE lists of boilers that could conceivably burn coal indicate that 25 million tons of additional coal demand could be generated if these plants converted However, conversion of all these plants is unlikely by 1985. EEA believes that a coal demand increase of 10 to 15 million tons from these plants might be realistically expected by 1985

EEA believes the coal demand from existing plants will, in effect, remain unchanged. While coal demand from the oldest plants will decrease marginally, accelerated oil retirement, wheeling, and conversions should serve to offset the decrease While EEA cannot predict perfectly offsetting decreases and increases in demand, the margin for error is slim, probably 10 million tons at the most Thus, EEA assumes the existing component of demand will increase through wheeling by 5 million tons by 1985

Demand for coal from new plants was estimated on the basis of capacity additions planned through 1984 These additions imply an overall coal demand growth rate of five percent per annum While electricity demand will not grow at this rate, planned nuclear capacity additions will be delayed and, as a result, utility coal demand will grow more quickly than electricity demand.

EEA projects that electricity demand will grow at a 3.8 percent rate over the next seven years, bringing total generation in 1985 to about 2,850 million KWh. In comparison, utilities predict an overall 5 percent

growth rate to 3,070 million KWh in 1985 EEA also assumes that nuclear capacity additions will lag approximately two years behind projected completed dates This assumption is supported by comparison of historical projected and actual completion dates and the current caution regarding the future of nuclear power Such a lag would prescribe projected 1985 nuclear generation by about 190 million KWh, nearly equal to the margin between the utilities and EEA's projection for total electricity demand By aggregating only those plants due on line by 1984, EEA is conservatively estimating 1985 coal demand This is because plants on line any time in 1985 will also contribute to 1985 coal demand This aspect of the methodology is also intended to account for slower electricity demand growth than the utility's forecast. Some delay in completion of coal-fired plants will probably occur, and plants due in 1985 would be the first ones to be removed from the 1985 demand component

5 4 2 Additional Assumptions

While total 1985 utility coal demand was based simply on coal demand of existing plants plus demand from plants due on line through 1984, several other assumptions were required to arrive at demand expressed in terms of Btu's and segregated by sulfur content For each existing plant, the most recent DOE data (1978) regarding average heat content and sulfur content of delivered coal were used. Coal demand in Btu's for each plant was obtained by multiplying 1978 coal demand and the average heat content The sulfur category of each plant's coal demand was determined through calculation of emissions in pounds of SO_2/MMBtu from sulfur and heat content values. While it is conceivable that some shift among sulfur categories would occur, any shift will probably be slight Since most plants are now in compliance with their SO_2 emission limits, shifts in coal use will only occur if specific State Implementation Plan (SIP) limits are changed At this time, few SIP revisions with respect to SO_2 appear likely to occur.

EEA's approach to new plant demand relies on the announced capacity of each plant and assumptions regarding capacity utilization and heat rate The methodology assumes a nationwide average capacity factor of 60 percent which is reasonable in light of historical data for new coal-fired plants. A heat rate of 9800 Btu/kWh was also assumed to represent an average new coal boiler. Demand in Btu's is determined by multiplying capacity (in KW) by 8760 hr/year by the capacity factor times the heat rate

5 4 3 Demand Projection by Sulfur Content

To determine the sulfur content of the coal each plant will use, two other characteristics are important SO_2 regulation and compliance strategy Plants coming on line through 1984 are subject to either the "old" or the "new" Federal New Source Performance Standard Under the old standard of 1.2 pounds SO_2/MMBtu, a plant could comply through burning compliance coal (e.g , 0 6 percent, 12,000 Btu/lb) or through utilization of an SO_2 scrubber with any coal The new standard is more complicated but requires scrubbing for all coals, the degree depending upon the sulfur content of the coal Most plants due on line through 1984 will be subject to the old standard For each of these plants, the EEA data base indicates whether a scrubber will be utilized or not. The critical factor is determining what type of coal will be burned Plants with no scrubber must burn "compliance" coal, which is only available from certain coal districts. Plants with scrubbers may obtain whatever coal is least expensive and suitable for their boilers. Plants subject to the "new" NSPS, on the other hand, will use whatever coal/scrubber combination is cheapest, but some type of scrubber must be used Thus, for the purposes of the model, new power plant coal demand is divided into three categories· old NSPS with scrubber, old NSPS without scrubbers, and new NSPS.

To summarize, within each region the model defines the demand sector as a combination of five plant types as follows:

1) Plants not subject to NSPS II which must use compliance coal because they do not have scrubbing equipment

2) Plants not subject to NSPS II which may use compliance coal or coal which requires partial (dry) scrubbing

3) Plants not subject to NSPS II which may use any type of coal because they have full (wet) scrubbing equipment

4) Plants that are subject to NSPS II which choose to install (dry) partial scrubbing equipment and thus may use compliance coal or coal requiring partial scrubbing

5) Plants subject to NSPS II which choose to install wet scrubbing and may use any type of coal

5 4 4 Sources and Limitations

The information on EEA's coal demand data base comes from a variety of available sources. Capacities for new and existing plants are taken primarily from the 1979 edition of Steam Electric Plant Factors published by the National Coal Association, although a variety of other sources have also been used Heat content, sulfur content, and delivered tonnage for existing plant fuels are taken from DOE's report Cost and Quality of Electric Utility Plant Fuels - 1978. Information regarding scrubbers is obtained from EPA's Utility FGD Survey The report is published quarterly and monitors scrubbers planned for new plants or in operation on existing plants. The applicable sulfur regulations for new sources (new or old NSPS) was determined for each power plant unit through communication with each of EPA's regional offices The sources for the data used to develop 1985 coal demand characteristics are considered as reliable as any available.

Most of the important limitations to the methodology employed have been discussed earlier in this section. The most important implicit assumption is the electricity demand growth rate A small change in the annual

growth could make a significant difference in coal demand Other factors subject to utility or regulatory decisions could change on a power plant-specific basis. For instance, an existing plant may become subject to new SO_2 regulations that would require coal of a different sulfur content, or a utility may alter its compliance strategy However, only a few of these changes are likely to occur in the next five years Sulfur regulations are no longer in such a dynamic stage as they were in the years immediately following the Clean Air Act And plans for plants due on line in the next five years are unlikely to change as many are already under construction and others will be started in the near future Whatever changes might occur could not greatly affect the 1985 demand picture.

5 4.5 Demand Projection Results

The results of the 1985 utility coal demand projection are shown in Table 5-4 About 60 percent of the coal demand will be from existing plants and the remainder from new plants Most existing plants will burn high sulfur coal, while new plants will rely on compliance coal to circumvent the capital costs associated with partial scrubbing

The 1985 projection also shows that about 40 million tons of coal will be burned by new plants subject to NSPS II regulations. These plants may opt for full or partial scrubbing depending on the relative delivered prices of the various sulfur content coals The linear programming model determines how this coal demand will be allocated in order to minimize the utilities coal-burning costs

5.5 ELECTRIC UTILITY DEMAND IN 2000

Predicting the long run utility demand for coal requires a different approach than that used to forecast 1985 demand The 1985 projection

TABLE 5-4

DEMAND PROJECTIONS IN QUADS

1985

	C	L	H	N	Total
Electric	5.2	2.4	9 2	1 0	17.8
Industrial	1.3	0 7	0.7	---	2 7
Met Coal	1 1	1 1	---	---	2 2
Exports	0 6	0 7	---	---	1.3
TOTAL	8 2	4.9	9 9	1 0	24 0

2000

	C	L	H	N	Total
Electric	4.9	1 1	8 5	15.1	29.6
Industrial	3 0	3 0	3.5	----	9 5
Met. Coal	1.3	1.3	---	----	2 6
Exports	0.8	1 0	---	----	1 8
Synthetics	---	2 5	---	----	2.5
TOTAL	10.0	8 9	12 0	15.1	46 0

Implied Growth Rates

	1985	2000	Annual Growth
Electric	17 8	29 6	3.4
Industrial	2.7	9.5	8.7
Met. Coal	2.2	2 6	1.1
Exports	1 3	1.8	2.2
Synthetics	0.0	2 5	---
TOTAL	24 0	46.0	4 4

Source: EEA estimates.

relies on the aggregation of very specific coal demand data for individual existing and planned coal fired utility plants. In the longer run, however, this approach breaks down as the uncertainty surrounding a given utility's generating plans becomes large. While a given utility may be reasonably certain about its generating plans in five years, projections by utilities over twenty years are too unreliable to be useful

The steps used to project utility coal demand by region can be summarized as follows:

- Determine the aggregate electricity demand annual growth rate for the U S between 1985 and 2000
- Calculate regional demand growth rates that are consistent with the aggregate growth rate.
- Assume that some portion of electricity demand will be generated by nuclear power plants, hydroelectric installations, and new technologies
- Assume that the remaining electrical generation is from coal fired utilities

These steps and the assumptions associated with them are described in detail below

5.5 1 Electricity Demand Growth Rate

It is generally acknowledged that electricity growth rates will not approach those witnessed during the 1950's and 1960's. Further, many of the factors which influence electricity demand growth have departed from the trends of the fifties and sixties. Two causal factors which have obviously departed from past trends are electricity price and population growth During the period between 1945 and 1970, the real price of electricity fell almost continuously. This trend reversed itself in 1971 and electricity prices have continued to increase during the '70's

The rate of population growth has also slowed, and current projections show that the U S population will grow at an average annual rate of 0 8 from 1975 to 2000, down from the 1.4 percent annual growth between 1950 and 1975.

In an article published in 1972, Chapman, Tyrall and Mount identified electricity prices, population, income, and alternative energy prices as the most important determinants of electricity demand [5/] Their econometric estimates of the elasticity of casual factors based on time series and cross-sectional data suggests a price elasticity of between -1.3 and -1 7, population elasticity of around 1, and income elasticities of between 3 and 5. Use of these elasticity estimates to forecast electricity demand in twenty years would be inadequate since they are based on historical and cross-sectional data and cannot account for changes in taste, values, habits, society, and the structure of the economy that are likely over the next 15-20 years. Instead, it is better to use these estimates as a starting point in an investigation of the likely factors that will affect long term electricity demand in each of the three sectors of the economy residential, commercial, and industrial

5.5.1 1 Electricity Demand. Residential

The residential sector accounted for 34 percent of electricity demand in 1977. According to the study by Chapman, et al , residential electricity demand displays a slight price elasticity (-1.3), in fact, the study shows that residential demand is the least elastic of the sectors. This is probably due to the fact that many uses of electricity in the home are relatively insensitive to the price of electricity (e.g., refrigeration, lighting, television) Technical changes in appliances are also contributing to higher electricity use in the residential sector. For example, most refrigerators now sold are automatic defrost models which consume 50-100 percent more energy Similarly, self-cleaning ovens,

larger color televisions, and central air conditioning systems are all built into the current stock of standard appliances New homes are likely to continue to include these electricity-intensive items

Two other factors will contribute to residential electricity demand growth

- o To the extent that electricity prices will rise more slowly than the prices of other fuels, electricity consumption in some of its more price elastic uses may rise Electric heat may gain market share as heat pump technology becomes widespread Since the cost of entertainment outside the home may involve fuel intensive travel, demand for home entertainment appliances may be encouraged Thus, since electricity prices are expected to rise less rapidly than other fuel prices, electricity's share of the residential energy mix can be expected to increase in the future

- o The next two decades will see the recent trend in fewer people per household continue Households having fewer people implies greater energy consumption per capita

The factors outlined above indicate that the slow growth in real electricity price and the change in lifestyles will combine to increase electricity consumption faster than population and per capita income The demand is not price elastic enough, nor are anticipated electricity price increases high enough, to mitigate this growth in electricity demand. Based on a growth rate in disposable income of 2.3 percent annually between 1985 and 1995, DOE forecasts an annual electricity growth rate of 3 0 percent annually [6/]

5.5 1 2 <u>Electricity Demand Commercial</u>

The commercial sector is expected to continue to experience a high rate of growth. The rapid expansion is due, in part, to the increased participation of women in the work force Many services previously available in the home will be purchased in the service sector

The commercial sector accounted for 28 percent of energy use in 1977 The electricity estimate by Chapman et.al suggests that the commercial sector has a higher price elasticity than the residential sector (-1 5), a higher population elasticity (1 0) and the highest income elasticity of the three sectors (0.9) As discussed previously, electricity's prices are not expected to rise as rapidly as the price of other fuels, so the price elasticity should not operate to significantly decrease demand.

The commercial sector is relatively electricity-intensive and is becoming more so (electricity's share of commercial fuel consumption has gone from 12 4 percent in 1962 to 23 3 percent in 1977). This is due to the growth in the installation of electricity-intensive air-conditioning systems, escalators, displays, etc The commercial sector's electricity intensity will combine with the high sectoral growth rate to result in a relatively high electricity demand growth rate for this sector During 1972 to 1979, when electricity prices rose and the economic performance was lackluster, electricity consumption grew by 4.9 percent annually in the commercial sector. The DOE projects that commercial electricity use will grow by about 3 percent annually, which is approximately the same rate as the projected GNP growth rate.

5.5.1 3 <u>Electricity Demand· Industrial</u>

The industrial sector is the economy's largest electricity consumer, accounting for about 38 percent of electricity demand in 1977 Industry is probably more adept at finding ways to decrease electricity use in response to higer prices, and this is verified in the Chapman study The study shows industrial demand to be the most price elastic of the three (-1.7). The energy intensity of this sector is declining as industry responds to higher prices of all fuels However the slower increase in electricity price relative to the price of other fuels will encourage electricity consumption. The DOE projects that electricity's share of

the industrial energy fuel mix will increase from 11.7 percent in 1977 to 16.3 percent in 1995 (Series C) The average annual growth rate is projected to be 4.8 percent, or approximately the same rate as the projected growth in industrial production

5.5 1 4 Summary and Conclusion

The factors outlined above suggest that·

- o Electricity demand will increase in each of the three sectors
- o Overall electricity demand growth will outpace GNP growth

What is not clear, however, is exactly how much faster electricity demand growth will outpace economic growth According to the DOE projections, annual electricity growth rates range from .4 to 1.3 percentage points higher than the assumed GNP growth (Series B, C, D), averaging approximately one percent. If a conservative GNP annual growth rate of 2 percent is assumed, this implies an electricity demand growth rate of 3 percent.

The three percent growth rate in electricity demand is more conservative than the DOE projections (which range from 3 7-3 9 percent per year) However it is in line with a Data Resource Institute projection of a 3 1 percent annual growth rate from 1978 to 2000.[7/]

The baseline 1985 electricity figure of 2850 billion KWh (see Section 5 4 1) and the three percent electricity demand growth rate result in an electricity generation forecast of 4440 billion KWh in 2000. If a higher GNP growth rate of 2.5 percent is assumed, then the resulting 3.5 percent electricity demand growth rate yields an electricity demand of 4775, or 7.5 percent higher Similarly, a 2 5 percent electricity growth rate yields a generation figure of 4127, or 7 percent lower. These differences are not critical to the demand forecast In fact, one would expect that if electricity demand is low, fewer nuclear plants would be built; similarly,

a higher electricity demand growth rate might encourage increased nuclear construction Therefore, the difference in the coal demand projection made by the electricity growth rate estimate may be even less than 7 to 7 5 percent

5 5.2 Disaggregation Technique

The next requirement of the analysis was the disaggregation of the total electricity generation figure among demand regions. This involved determining the relative electricity demand growth rates for the demand regions. Regional electricity demand growth is a function of those factors discussed above, namely price, population, income, and the price of other fuels The practical constraints imposed by the project preclude a detailed study to determine how the growth in all of these causal factors would vary by demand region to the year 2000 Therefore, projected population growth rates are used as the sole indication of the relationships between demand region growth rates [8/] That is

- States with high projected population growth rates were assumed to have high electricity demand growth rates; and
- If state A has a projected population growth rate of a, and state B has a projected population growth rate of b, then the ratio of their electricity demand growth rates are assumed to be $\frac{a}{b}$.

By using population growth rates in this way, we are assuming

- Growth in the residential and commercial sector is highly correlated with population growth,
- Growth in the industrial sector is also correlated with population growth;
- Sectional electricity demand growth is highly correlated with sectoral economic growth

Assumptions one and three are not unreasonable: population is the residential sector, and the service sector will grow with its markets,

part of which is the residential sector. Sectoral electricity demand growth has been shown highly correlated with sectoral growth (see previous section) The second assumption is not as strong To the extent that industry requires labor, industrial growth and population growth will be complementary. Recent labor force migrations are captured in the population projections (migration were estimated based on 1970-75 trends) The areas with high population growth rates are in the Southwest and the West where the highest industrial growth is expected However, regional industrial growth is a function of resource availability in the region (such as cheap, abundant energy), required tax structure, environmental regulation, and a host of factors not captured by population Despite these shortcomings, use of population growth was acknowledged as the best single indication of electricity demand growth relationships among regions by electricity demand forecasters at the Department of Energy 9/

The regional estimates of electricity demand growth rates were determined by solving iteratively the following equation for X

$$D_{2000} = \sum_{i=1}^{15} D_i \, (1 + Xr_i)^t$$

D_{2000} = total generation in 2000
D_i = generation in the i^{th} region in 1985
r_i = population growth rate for 1985-2000 in the i^{th} region
X = factor to be solved

5 5 3 Electricity Generation from Other Sources

Once regional generation is known, all that remains is to deduct the nuclear, hydroelectric, and other source generation Regional figures for these, and the resulting generation by coal-fired utilities in the year 2000 are shown in Table 5-5

TABLE 5-5

PROJECTED ELECTRICITY GENERATION BY SOURCE AND REGION

YEAR 2000

(MMM KWH)

Region	Total Generation	Nuclear	Hydro	Other	Coal
1	254	173	28	14	39
2	200	48	2	11	139
3	183	52	0	6	125
4	152	60	2	7	83
5	299	102	8	16	173
6	564	120	0	35	409
7	155	76	4	8	67
8	564	54	0	4	489
9	280	66	30	9	175
10	243	35	12	13	183
11	114	11	3	8	92
12	461	142	3	23	293
13	78	0	3	2	73
14	202	18	0	13	171
15	694	131	175	34	354
TOTAL	4443	1088	270	220	2865

Source: EEA estimates.

5.5 3.1 Nuclear Generation

Predictions regarding the future of nuclear power have covered a wide range since the accident at Three Mile Island. Some believe few additional nuclear plants will come on line. Others predict steady increases in nuclear's share of electricity generation, just as the utilities predicted before the accident. On developing projections for the year 2000, EEA has adopted a middle-of-the-road approach. EEA has assumed that all planned nuclear plants will be on line by the year 2000, but that no additional capacity not now committed to construction will be built. Some announced plants are due on line as late as 1994, but most announced plants are due by 1990 Thus, plants that could be announced for the 1990's will not be included as contributing to electricity production EEA feels the assumption is adequate considering the very uncertain regulatory and political climate While capacity beyond that already announced could be added, some announced capacity has recently been cancelled and more cancellations are likely Furthermore, as stated earlier, there will continue to be delays of one to four years in actual service dates, especially for plants due in the late 1980's. Many sources for announced plants exist EEA used a DOE publication, U.S Central Station Nuclear Electric Generating Units Significant Milestones, published September, 1979.

Four regions required adjustments in the estimate of nuclear generation This is due to the fact that the planned nuclear capacity is inconsistent with the projected electricity demand growth rate in that region. In these cases, the planned nuclear addition would actually reduce the need for coal generating capacity already on line in 1985. We assumed that rather than retiring these coal-fired utilities early, nuclear construction would be limited Thus, for demand regions 4, 9, 10 and 12 only nuclear plants that currently have begun construction are to be on line in these regions in 2000

5.5.3.2 Hydroelectric Generation

Approximately 278 million megawatt hours of generating capacity were provided by hydroelectric facilities in 1978, with more than half of this generation occurring in the Northwest (demand region 15). Since there are few new opportunities for large generating capability hydroelectric installations in the United States, this analysis assumes that approximately this much power will be generated by hydroelectric power in the year 2000.

5.5.3.3 Other Sources of Generation

The combined effects of other electricity sources may make a significant contribution to generating requirements. These include: residual (oil-steam), gas turbines, distillate turbines, gas steam, pumped storage, hydrothermal, solar thermal, photovoltaics, wind systems, biomass-electric, and ocean thermal. For the purposes of the analysis, these other sources were assumed to contribute five percent of the required electricity generation, or roughly 220 million MWH. This figure is based on the DOE's forecast of approximately 5.5 percent market penetration for these sources in 1995 (Series C Projections).

5.5.4 Utility Demand for Coal in 2000

From the growth rate and generation-source estimates made above, the coal-fired percent of total generation in 2000 was estimated as follows:

1985 projection:		2850×10^6/MWH
Annual Growth Rate		3%
2000 projection		4440
Less:		
Nuclear generation	1085	
Hydroelectricity	270	
Other (5% of total)	220	
Coal fired utility generation		2865×10^6/MWH

Assuming a boiler efficiency of 9800 Btu/KWH, coal demand from electric utilities will be about 28 quads, or 1272 million tons of coal.

The results of the utility coal demand projection to 2000 are shown in Table 5-4 Total utility coal demand in 2000 is 29 6 quads, or roughly 1400 million tons (using 10,000 Btu's/lb of coal). This implies a growth rate of 3.4 percent annually from 1985 to 2000, slightly higher than the estimated electricity demand growth rate of 3 percent annually

All coal capacity built between 1985 and 2000 falls, of course, under the revised NSPS regulations. As such, these utilities may chose coal of any sulfur content depending on their choice of scrubber, as determined by the model.

Coal demand by plants under SIPs that are still on line in 2000 is assumed to have the same sulfur content distribution as in 1985 Retirement of coal-fired utilities between 1985 and 2000 was estimated at roughly 150 million tons (3.15 quads).* This 3 15 quads of coal demand are added to the coal demand under revised NSPS.

5 6 INDUSTRIAL COAL DEMAND FORECAST

5 6 1 Methodology

The forecasts of coal demand from the industrial sector are made using EEA's Industrial Fuel Choice Analysis Model (IFCAM). Based on projected industrial fuel demand (determined exogenously), IFCAM considers capital costs, operating and maintenance costs, environmental costs, and policy measures to estimate fuel shares in the 1985 to 1995 time frame

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* This figure was arrived at as follows. The fact that 318 million tons of coal were consumed in 1970, and 174 in 1960 implies that during the 1960's approximately 150 million tons of coal capacity was added Therefore, in 1970, approximately half of coal-fired utility capacity was greater than 10 years old By 2000, the 150 million tons was greater than 40 years old, or the assumed life of a coal fired plant. Thus, 150 million tons is retired between 1985 and 2000.

IFCAM relies on a very high level of disaggregation to make fuel share projections ˉIn each of 10 Federal regions, the projected level of demand by fuel and by industry determines the type and number of boilers Each combustion unit is characterized according to location within a region, industry, size, and capacity utilization. Existing boilers are sited in their actual location while new boilers and all process heaters are located according to historical patterns.

Fuel choice is limited by both technical and environmental constraints, and these are built into the model. Given these constraints, the fuel choice investment decision is simulated for each individual combustor The costs of coal are compared to those of using other fossil fuels and the investment decision simulated using a standard net present value (NPV) calculation When technical or environmental problems preclude use of a certain fuel, the next best economic alternative is chosen. The components considered in the NPV calculation include capital, operating and maintenance costs, construction period, revenue life, depreciation life, applicable investment tax credit, fuel price, and taxes In this way, the model estimates the industrial fuel share-of oil, coal, and gas after all the incentives and fuel type constraints have been evaluated

The industrial coal demand forecasts were made based on assumptions in three areas relative fuel prices, environmental regulations, and federal programs to encourage coal use

Oil and gas prices are taken from DOE's Mid-Term Energy Forecasting System Coal prices were estimated by EEA independently of the EEA linear programming model. The price of oil is projected to be $23.30 per barrel in 1985 and $35 40 per barrel in 1995 (constant 1978 dollars). In nominal dollars, assuming 6% annual inflation, the 1985 oil price is $35 per barrel, and $95 in 1995

Environmental regulations as they apply to the industrial sector remain uncertain However, IFCAM can be run under a number of regulatory assumptions. The IFCAM projections used in this analysis assumed current New Source Performance Standards would apply throughout the forecast period These standards require that all boilers with firing rates of 250 MMBtu's/hr and greater use flue gas desulfurization with high sulfur coal and electric-static precipitation with low sulfur coal (It is possible that in the future, the size cut-off may be lowered to include smaller boilers which would reduce coal's attractiveness as a fuel for these boilers. However, as coal use is generally not as economical for smaller boilers due to high capital costs, the absolute change in coal consumption would be slight) Boilers not subject to NSPS regulations are required to comply with state implementation plans (SIP), which vary by state and are not likely to be significantly adjusted throughout the forecast time frame. Non-boiler coal uses are not subject to NSPS Many process uses actually remove sulfur in part of the process, so even future regulations should not affect process coal demand

Federal programs to encourage the industrial use of coal include tax incentives, rapid depreciation of coal capable capital, and mandatory coal use regulations Under the National Energy Act of 1978 industries investing in coal capable equipment are eligible for an additional 10% investment tax credit and accelerated depreciation These tax incentives are assumed to continue over the model time frame. (The added investment tax credit is scheduled to expire in 1983, but it may be renewed) The Fuel Use Act of 1978 requires all new boilers with firing rates exceeding 100 MMBtu's/hr and all existing coal capable boilers to burn coal unless excepted This is simulated in the model

5.6.2 1985 Projection

Table 5-4 shows the results of the 1985 industrial coal demand projection Total industrial coal use in 1985 is projected to be about 2.7 quads, or

110 million tons This includes roughly 26 million tons of coal used in process heat The annual growth rate implied by this projection is 8.3 percent, a sharp reversal of coal's previous demand decline in this section However, this growth rate is consistent with recent interest demonstrated by several large manufacturers in installing coal fired boilers For example, DuPont is retiring oil-fired boilers at its eastern U S locations and replacing them with coal-fired units Moreover, the pricing of natural gas up to the residual oil-equivalent price is prompting industrial conversions to coal.

5 6.3 2000 Projection

The IFCAM model does not project coal demand to 2000. Therefore, the 1995 projection was extrapolated by using the implied 1990-1995 fuel demand growth rates Coal's growth rate during this five year period averages 9 3 percent annually, mostly at the expense of natural gas The growth in coal penetration is assumed to fall off such that it penetrates roughly 50% of the industrial fuel market by 2000 or 9 5 quads

The implied growth rate from 1985 is 8 7 percent annually This estimate is higher than most other forecasts DRI estimates industrial coal use will be 290 million tons per year, a growth rate of 4 percent annually The high rate reflects IFCAM's assumption as to the age distribution of boilers Many of the industrial boilers in use in 1985 will be World War II vintage boilers (built during the war years and the expansion of the 1950's) approaching the end of their useful life Therefore, in the 1985-95 period, the effect of the high retirement rate and the incentive to install coal-fired boilers will combine to accelerate coal's industrial market penetration

5.7 OTHER MARKETS DEMAND FORECAST

5 7 1 Metallurgical Coal Forecast

The 1985 and 2000 metallurgical coal demand forecasts were developed after examining the DOE and DRI forecasts Assuming a GNP growth rate of 2 percent annually, the steel industry can be expected to grow at less than 2 percent The DRI projections show met coal demand growth at 2 6 percent annually between 1978 and 1985, and 1 7 percent annually between 1985 and 2000.

DOE 1985 projections (Series C) showed a lower growth rate to 1985, about 2.0 percent annually. Since the conservative forecast is more consistent with EEA's estimate of economic growth, and since the short term market outlook has generally been pessimistic (see section 5 2.3), the estimate of 86 million tons in 1985 is used. Similarly, the 2000 projection is based on DOE's 1995 projection extrapolated by 2 percent annually This results in 105 million tons of met coal demand compared to 116 million tons projected by DRI The projected met coal demand was split between compliance and low sulfur coal, and distributed among the demand regions according to 1978 consumption patterns (see Table 5-4)

5 7 2 Exports

With current predictions that the coal export market will boom, particularly due to increased steam-coal sales, (see Section 5 2 4), the optimistic 1985 projection of 70 million tons (DRI) was used in the EEA model (see Table 5-4).

ICF shows a decline in exports to 50 million tons which seems unlikely DRI's 2000 export projection of 97 million tons is in closer agreement with ICF's projection of 100 million tons, and the DRI projection was used The export projections were split between compliance and low sulfur coal, and exported coal was assumed to travel to Virginia ports for shipping.

5.7.2 Synthetic Fuels

Estimates of the size of the synthetic fuel industry by 2000 vary widely ICF pessimistically projects that only 25 million tons of coal will be required for syn-fuel production, slightly more than the coal needed to supply one syn-fuel plant DOE is far more optimistic in their projection of 300 million tons per year [10/] EEA chose a mildly optimistic figure of 150 million tons, which is in line with DRI's forecast, this forecast assumes that roughly 7 to 8 syn-fuel plants are operating in 2000 (see Table 5-4).

Distribution of the projection among the demand regions is based on the following assumptions

- No coal liquefaction takes place in the West, where shale oil will be the dominant oil source, further, water availability will hinder siting of coal liquefaction plants in the West
- Coal demand is evenly split between liquefaction and gasification plants.
- Liquefaction plants are built in Kentucky and West Virginia
- Gasification plants are in Colorado, Montana, Wyoming, Texas and North Dakota

5 8 SUMMARY AND CONCLUSIONS

The demand projections for 1985 and 2000 that are used in the EEA coal model are summarized in Tables 5-6 and 5-7 These show coal consumption in quads by sulfur category (compliance coal, low sulfur coal, high sulfur coal, and unassigned)

The demand scenario projected by EEA is significantly different from other forecasts only in the industrial sector in the year 2000 EEA's forecast is high because it assumes 1) a high turnover in industrial coal burning capital between 1985 and 1995; and 2) that relative fuel prices and federal energy policy will effect a large shift to coal. To

TABLE 5-6

TOTAL COAL DEMAND
(in quads)
YEAR 1985

Demand Region	C	L	H	N
1	.2	4	.1	.1
2	*	.1	.1	0
3	6	.3	1.0	0
4	6	.5	.9	.1
5	1 1	1.5	6	0
6	.2	1	8	2
7	3	.2	.5	.1
8	8	3	.7	1
9	.2	.2	1.2	1
10	8	3	1.0	.1
11	6	*	*	*
12	1 6	6	1 9	1
13	.3	.1	.5	0
14	.7	.2	.4	.1
15	.2	.1	.2	*
	8 2	4.9	9 9	1.0

Note: * = less than 0 1 quads

Source: EEA estimates.

TABLE 5-7

TOTAL COAL DEMAND
(in quads)
YEAR 2000

Demand Region	C	L	H	N
1	.4	7	3	2
2	*	2	1	1 2
3	7	.3	1 1	3
4	7	4	9	1
5	1 4	2.4	.7	7
6	2	*	7	3 3
7	.3	.3	7	.3
8	1.2	1.2	1.4	3.3
9	3	9	1 3	.6
10	8	2	1.1	.3
11	.8	.3	3	3
12	1.7	.5	2 0	5
13	.3	6	.5	.1
14	.7	.6	.5	6
15	5	.3	.4	3 3
	10 0	8 9	12.0	15 1

Note: * = less than 0.1 quads.

Source: EEA estimates

the extent that these assumptions are overstated in the industrial demand forecast methodology, the coal demand figure for 2000 is high.

The high industrial demand growth rate relative to demand growth in coal's other markets implies that in 2000, the industrial sector will have about 20 percent of all coal produced, compared to 11 percent in 1985 and less than 10 percent currently

Because of the uncertainty inherent in each component of the demand forecast, the overall projection is necessarily uncertain The 2000 projection represents little more than an informed guess. Further work is indicated to refine electricity demand growth estimates, develop usages in the export and metullurgical coal market, and delineate several scenarios of industrial coal use, the market with the most indefinite future

5.9 NOTES

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2. Ibid., p. 58.

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4. Heller, James and Charles Mann and EEA, Coal and Profitability, An Investor's Guide, McGraw Hill, p. 47-54

5. D. Chapman, T. Tyrell, T. Mount, "Electricity Demand Growth and the Energy Crisis," in Science, Vol. 178, No 4062, November 17, 1972 pp. 703-707.

6. Energy Information Administration, Annual Report to Congress, Vol. 3 (1978). Series C. Projection.

7. Data Resources, Inc , "The Divergence of Coal and Oil Prices -- What Does It Really Mean (Abstract)," 1979.

8 U.S Department of Commerce, Bureau of the Census, "Illustrative Projections of State Populations by Age, Race and Sex 1975-2000." Series P-25, No 796 March, 1979

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10 EIA, loc cit

6. RESERVE CHARACTERIZATION

6.1 INTRODUCTION

An objective of EEA's coal model is to identify the coal reserves which can be mined using current methods. To produce these results, the model's description of reserves must: 1) include all the known coal which will be available to mine in the year 2000 and beyond, and 2) these reserves must be described at a level of detail which allows evaluations of the type of mining technology which would probably be used to extract specific seams and deposits.

The coal reserve descriptions which are used in other coal demand/supply models are not suitable for use in the EEA model for two reasons The first drawback of conventional reserve descriptions, such as those prepared by the U S Bureau of Mines, is that they describe only a small portion of the total coal resources The Bureau of Mines estimates, for example, include only the measured and indicated reserves, that is, only the coal which is estimated to be in the area within one and one-half miles from a specific sampling point. The second drawback of conventional coal reserve data is that they fail to describe on a sufficient level of detail reserve seam thickness, slope, pitch, and other characteristics which determine the logical choice of mining technique. These two drawbacks do not jeopardize the usefulness of the Bureau of Mines' reserve estimates for their intended purpose of gross reserve characterization; the BOM estimates are periodically updated as the results of recent exploratory drilling are processed and more detailed descriptions are available from other sources. These drawbacks do, however, preclude the use of aggregate estimates in a model such as EEA's.

The objective of EEA's reserve data base, therefore, was to describe as much of the U.S. coal resources in as precise a level of detail as possible EEA expanded the coal resources described in conventional data bases by including the results of recent exploration activities, obtaining reserve descriptions which are normally not included due to ownership problems such as the Navaho holdings in the San Juan Basin, and extrapolating the location of inferred (greater than 1.5 miles from a sampling point) coal reserves. The detailed descriptions of the minability characteristics of specific scans were prepared through extrapolations based on the geological structure of the coal basins

This section will describe how these analyses were performed Six topics are evaluated.

- o Sources of Information
- o Supply Regions and Coal Types
- o Mine Type Descriptions
- o Allocation of Reserves to Mine Types
- o EEA Coal Model Reserve Base
- o List of References

6.2 SOURCES OF INFORMATION

The basic information on coal in the United States is contained in about 1,500 geologic reports published by the U S Geologic Survey (USGS) and in a substantial and possibly equal number of reports published by other organizations, including state geological surveys, the U.S. Bureau of Mines (USBM) and professional societies. Additional information is contained in the proprietary journals and records of coal companies, railroads, and land-holding companies. For most states, summary reports on the geology and occurrence of coal, including estimates of coal resources, have been prepared from the detailed information in these various sources. The reserve data input for the EEA Coal Model is based primarily upon these summary reports (see Section 6.7).

In most of these reports, coal-resource estimates are divided into three categories according to the relative abundance and reliability of data used in preparing the estimates. These categories are termed "measured," "indicated," and "inferred " Coal-resources in all three categories are included in the EEA reserve base.

Measured resources are based on individual mapped coal beds for which the points of observation and measurement are so closely spaced, and the thickness and extent of the coal beds so closely defined, that the computed tonnage is judged to be accurate within 20 percent of the true tonnage The points of information used to evaluate coal resources at the "measured" confidence level are usually a half-mile apart.

Estimates of indicated resources are computed in the same way as measured resources except points of information may be as much as 1½ miles apart Estimates of inferred resources are based primarily on an assumed continuity of coal beds into more remote areas downdip from and behind areas containing measured and indicated resources Most coal classified as inferred lies 2 miles or more from a mapped outcrop or from points of precise information

Approximately 61 percent of the U.S coal reserves are classified as inferred coal This is a large figure because of the lack of data in areas remote from outcrops. It does, however, express the approximate amount of coal that can be inferred to be present on the basis of current geologic information. Additional geologic mapping, exploratory drilling, and study in areas of inferred resources would undoubtedly increase the percentage of measured and indicated resources and decrease the percentage of inferred resources Since the EEA coal reserve base is used to predict coal supply patterns 20 years into the future, it is appropriate to include inferred coal resources in the data base.

6 3 SUPPLY REGIONS AND COAL TYPES

The EEA coal model contains 15 supply regions which include all of the important bituminous, subbituminous and lignite deposits in the conterminous U.S The supply regions represent areas in which the coal rank, geology and quality are roughly homogeneous. For each supply region, an estimate has been made of the average rank, Btu content and distribution of reserves by sulfur content. The distribution of reserves by sulfur content was estimated for three ranges of pounds SO_2/MMBtu (designated hereafter as #), less than or equal to 1.2#, 1.3 to 2.4#, and greater than 2.4# This distribution was determined for each supply region by comparing the accumulative tonnage in each sulfur category (as estimated by the USBM) to the average Btu content. The three ranges correspond to the compliance, low and high sulfur categories used for determining coal demand The low sulfur category includes 2 1-2 4# coal because this coal can be blended or mixed with the 1 3-1.9# coal to achieve an average 2 0# product Table 6-1 lists the supply regions and the coal types used in the EEA model.

6 4 MINE TYPE DESCRIPTIONS

Table 6-2 includes all of the parameters used to describe the prevailing geologic conditions in each supply region. Together, these parameters define the mining conditions associated with different portions of the reserve Each parameter is broken down into categories which have generally different effects on the type and/or cost of mining.

The categories of each parameter have been designated by superscripts which are used in coding the different mine types. Four basic mine types are used in the EEA model; contour and area stripping, room and pillar continuous mining, and longwall mining (see Section 7 2 1 for a discussion of mining technology) A total of five parameters are used to describe each basic mine type

TABLE 6-1

SUPPLY REGIONS AND COAL TYPES

	SUPPLY REGION	RANK	BTU/LB	SULFUR 1/ ≤ 1.2	>1 2 to 2 0	>2 0
1	OHIO	BITUMINOUS	12,500	---	.03	0 97
2	PENNSYLVANIA MARYLAND NORTHERN W VA	BITUMINOUS	13,500	---	10	0 90
3	SOUTHERN W VA. EASTERN KENTUCKY VIRGINIA NORTHERN TENNESSEE	BITUMINOUS	13,500	.45	43	0 12
4	SOUTHERN TENNESSEE ALABAMA	BITUMINOUS	13,500	12	.63	0.25
5	WESTERN KENTUCKY INDIANA ILLINOIS	BITUMINOUS	11,000	---	05	0 95
6	KANSAS MISSOURI NEBRASKA IOWA	BITUMINOUS	11,000	---	---	1.00
7	OKLAHOMA ARKANSAS	BITUMINOUS	13,000	---	65	0.35
8	TEXAS LOUISIANA ARKANSAS	LIGNITE	7,000	---	---	1.00
9	MONTANA NORTH DAKOTA	LIGNITE	6,000	---	.80	0 20
10	MONTANA	SUBBITUMINOUS	8,500	.30	.70	---
11	WYOMING (PRB)	SUBBITUMINOUS	8,000	.30	70	---
12	SOUTHERN WYOMING NORTH CENTRAL COLORADO	SUBBITUMINOUS	9,000	40	60	---
13	NORTHWEST COLORADO NORTHERN UTAH	BITUMINOUS	12,500	40	.60	---
14	SOUTHERN UTAH SOUTHERN COLORADO	BITUMINOUS	11,000	.20	.80	---
15	NEW MEXICO ARIZONA	SUBBITUMINOUS	12,000	.40	.60	---

1/ Pounds of SO_2/MMBtu

TABLE 6-2

PARAMETERS USED IN THE MINE TYPE/RESERVE CHARACTERIZATION *

(1) TYPE	(2) METHOD	(3) SEAM THICKNESS (INCHES)	(4) SLOPE (DEGREES)	(5) PITCH (DEGREES)	(6) STRIP RATIO	(7) BLOCK SIZE (MMT)	(8) OVERBURDEN THICKNESS (FEET)	(9) DRIFT/ SHAFT
SURFACE[1] MINING	AREA[1]	28 - 41[1]	≤10[1]	0 - 10[1]	5·1[1]	6[1]		
		42 -119[2]	11 - 20[2]	11 - 30[2]	10 1[2]	20[2]		
		≥120[3]	21 - 30[3]	>30[3]	20·1[3]	150[5]		
	CONTOUR[2]	28 - 41		0 - 10	10:1			
		42 -119			20.1			
UNDERGROUND[2]	ROOM & PILLAR[3]	28 - 41[1]		0 - 10		6	0 -500[1]	D[1]
		42 -119[2]		11 - 30		20	500-2000[2]	S2
		≥ 120[3]				40[3]		
	LONGWALL[4]	28 - 41[1]		0 - 10		60[4]	500-2000	D[1]
		42 -119[2]		11 - 30			2000	S[2]
		≥ 120[3]		>30				

* Superscripts indicate mine type coding

Surface mines are characterized by thickness, slope, pitch, stripping ratio, and block size Surface contour mines are used on medium and steep slopes where the coal outcrops These conditions are found nearly exclusively in Appalachia. Only one block size is considered for contour mines; this is because economies of scale are not relevant to contour stripping, since the actual equipment and pit layout can occupy only a small area at a time. Area stripping is used on gentle slopes where seams are continuous over broad areas Unlike contour mines, western area mines include thick (>119 inches) and pitching seams Area mines are characterized by large mining blocks and are capable of producing as much as 6 75 million tons or more per year.

Underground mines are characterized by seam thickness, pitch, block size, overburden and whether the mining block is drift or shaft mineable. Room and pillar mines are assigned to all flat and moderately pitching seams with 2000 feet or less of overburden Seams that are steeply pitching or under deep overburden (>2000') are considered to be mined by the longwall method Mines in Appalachia may be restricted to small areas of reserves such as a drift operation which mines a reserve part way up a narrow ridge Therefore, small and medium reserve blocks are assigned to drift mines and large blocks to shaft mines

Since certain categories are absent in each supply region, there are only 180 permutations or mine types. For example, central Appalachia is assumed to contain no significant reserves which dip greater than 10 degrees; therefore, all mines in this region are characterized by relatively flat lying seams

6.5 ALLOCATION OF RESERVES TO MINE TYPES

The general approach used to allocate reserves to mine types was to consider each state separately and then group together the results for states belonging to the same supply region

The methodology for allocating state reserves to mine types involved eleven basic steps They are·

1 Determine percentage of total identified reserves greater than 28 inches thick that are surface mineable

2. Reduce the reserves allocated to surface and underground mining methods by the appropriate availability factor

3. Estimate the distribution of reserves by seam thickness

4 Estimate the distribution of surface mineable reserves by slope

5 Estimate the distribution of reserves by seam pitch.

6 Distribute the surface mineable reserves by maximum stripping ratio

7 Estimate the distribution of underground mineable coal by thickness of overburden

8 Estimate distribution of reserves by block size

9 Classify underground reserve blocks as drift or shaft mines.

10 Distribute coal to mine types

11 Distribute total available coal in each mine type into categories of sulfur content.

These eleven steps are discussed below.

6.5 1 Step 1 - Determine Percentage of Reserves Which Are Surface Mineable

The initial data source used to estimate the strippable portion of the reserv base was the USBM's Mining Industry Surveys, 1976 The surface reserves given by BOM were based on various maximum economical stripping ratios that changed from state to state depending upon the relationship of supply and demand For use in the EEA Coal Model, these estimates were standardized to include all coal that would be mineable at a 20 1 ratio of feet overburden to feet coal, a ratio higher than the maximum economical stripping ratio in most regions This was done so that

current economic constraints would have less of an impact on future projections

The methodology used by USBM to estimate surface reserves was to measure the length of the coal outcrop and multiply this distance by the average width of the mining bench (as defined by the maximum stripping ratio, average seam thickness, and surface slope). This area was then multiplied by the average seam thickness and converted to tons coal by using the factor of 1800 tons/acre foot (1760 for subbituminous coal and lignite). Similar methodologies were used by other agencies and organizations which participated in estimating surface reserves, including the USGS, state geological surveys, coal mining companies and railroad companies In order to standardize these estimates, they were increased proportionately to differentiate between the ratio used in the original estimate and the 20 1 standard For example, surface reserves in West Virginia which were calculated at a ratio of 15:1 were increased by a factor of 1.33 to include the additional coal that could be mined at a 20 1 ratio This is a reasonable approach because it is equivalent to the increase in average bench width that would be used in the calculations if a greater strip ratio was considered. To account for this increase of the allotted surface mineable reserves the underground reserves in the 0-1000 feet category were reduced by an amount equal to the increase in surface reserves.

This adjustment of the reserve base was done primarily for bituminous coal. Surface reserve estimates for subbituminous coal and lignite in the northern Great Plains (North Dakota, Montana, and Wyoming) and Gulf Coast regions (Texas, Louisiana, Arkansas) were used in their original form, which typically included coal up to a 5.1 or 10 1 maximum stripping ratio

6.5 2 Step 2 - Reduce Reserves by Appropriate Availability Factor

In order to account for constraints upon the availability of coal reserves included in the reserve base, the reserves were reduced by the following factors:

- o Underground reserves were reduced by 15 percent to account for land use and surface ownership, coal ownership patterns and geologic constraints such as overmining, undermining, and seam continuity.
- o Surface reserves in Appalachia were reduced by 20 percent and surface reserves in the Midwest were reduced by 25 percent These reductions were made to account for land use (towns, highways, railroads, utilities, and gas and oil wells) and coal which outcrops close to stream channels or is of poor quality
- o Surface reserves in the West were reduced by 15 percent. This reduction accounts in part for constraints similar to those found in Appalachia and the Midwest but also takes into consideration the impact of the Bureau of Land Management's (BLM) criteria for prohibiting mining in certain areas for environmental reasons (such as in alluvial valley floors)

6 5 3 Step 3 - Distribution of Reserves by Thickness

Three categories of seam thickness were included in the EEA reserve description, 28 to 41 inches, 42 to 119 inches and greater than or equal to 120 inches. The categories used in the EEA model were chosen because they conform with present mining practices and with past procedures in estimating resources. The 28-41 inch category represents coal that can be mined using especially designed underground mechanical loading machinery The 42 to 119 inch and the greater than or equal to 120 inch categories represent coal that can be mined by all types of mechanical cutting and loading machinery. These two categories are considered separately for block size considerations.

In a few states the categories of bed thickness differ from the categories outlined above. However, most of the states which deviated from

the standard did so because they (the states) contain little coal of commercial value and thus have categories typically smaller than the ones above An exception is Ohio which used categories of bed thickness for bituminous coal of 28"-54" and greater than 54" In these cases, the thickness distributions were matched to the categories in the EEA model which most closely compared with the original estimate.

6.5 4 Step 4 - Distribution of Surface-Mineable Reserves by Slope

In order to reflect the increased costs associated with surface mining on steep slopes, the reserves allocated to surface mining were distributed into categories of average slope The three categories included in the EEA reserve description are 0-10 degrees, 11-20 degrees, and 20-30 degrees Area mining was considered to be limited to gentle slopes in the first category Contour mining in Appalachia is assumed to be prevalent in all categories The slope characteristic is important for relating the increased stripping costs associated with steep terrain For example, in central Appalachia much of the strippable compliance coal ($\leq$1.2#) is located in steep hillsides and this may affect its competitive position in the coal market

The average slope was determined on a county level using 1 250,000 scale and 1·24,000 scale USGS topographic maps. The larger scale maps were used to segregate states into groups of counties having common terrain The 1.24,000 quadrangle maps were then used to calculate the average slope for each county Slope measurements were taken in a random checkerboard fashion across the county To determine the percent distribution by slope for a state, the county averages were then weighted by the portion of state reserves accounted for by each county

6.5.5 Step 5 - Distribution of Reserves by Pitch

The EEA reserve characterization includes three categories of pitch; 0-10 degrees, 11-30 degrees, and >30 degrees Pitch is an important

consideration in estimating the cost of both surface and underground operations A severely pitching seam can limit the size of surface operations because only a few hundred feet from an outcrop the seam may be too deep to mine Room and pillar continuous underground mining may be impractical with a strongly pitching seam, requiring the use of longwall methods

The methodology used to estimate reserves by pitch consisted of reviewing geologic reports and maps (on the county level wherever possible) and determining the distribution of coal-bearing areas into the three categories. The coal reserves were then treated as being evenly distributed across the coal-bearing area and were allocated to the three pitch categories in the same proportion as the areas were The region most affected by the pitch characteristic was the Green River/Hams Fork area, which is structurally complex and has seams which can dip as great as 25 degrees or more For most of the U.S coal reserves, however, regional pitch is negligible and usually less than 10 degrees Locally, seams may have severe pitch due to depositional or structural anomalies, but the frequency and impact of these phenomena upon the reserve base is impossible to estimate Generally, structurally complex areas containing strongly pitching coal seams are not likely to be subject to the intensive drilling and exploration that will occur in more favorable areas. Thus it is likely that the actual reserves contain more steeply pitching coal than is indicated by the available research

6 5.6 Step 6 - Distribution of Surface Reserves into Strip Ratio Categories

The portion of the surface reserves placed in Step 1 into the 20 1 strip ratio category was divided evenly into 10:1 and 20.1 strip ratio categories This was done to reflect the additional coal tonnage that could be produced if demand increased enough to make mining at higher strip ratios economical For example, steep slopes in southern West Virginia may severely limit the size of a surface mine operating at a 10.1 strip

ratio The bench width of such a mine would be so small that the reserves would be unprofitable to develop due to the small amount of coal that would be produced Much of the outcropping coal in such an area would thus be left undisturbed because the current economic limits on the strip ratio make start-up costs prohibitive in relation to the small net return in mineable coal However, with an increase in demand, it may become economical to mine at 20 1 thus opening new potential sites for surface operations.

6.5.7 Step 7 - Distribution of Underground Mineable Coal by Overburden Thickness

Most summaries of coal resources include some data on overburden thickness Whenever possible, coal resource data in these studies are divided into three major categories of overburden as follows 0-1000 feet, 1,000-2,000 feet, and 2,000-3,000 feet. In a few states where overburden is thin, the resources have been calculated in several subcategories within the 0-1000 foot category. In other states, where overburden is thicker or where information is inadequate, one or more of the major categories may be combined These states may also include estimates for coal in overburden categories greater than 3,000 feet

The three categories used in the EEA description are 0-500 feet, 500-2000 feet, and greater than 2000 feet The 0-500 foot category is allocated half of the reserves contained in the 1-1000 foot category in the original summary reports The 500-2000 foot category includes half of the 0-1000 foot category and all of the 1000-2000 foot category All other coal estimates are grouped into the greater than 2000 foot category.

6.5.8 Step 8 - Distribution of Reserves by Block Size

6.5 8 1 Introduction

The reserve block is defined as the amount of coal that can be logically committed to a specific type of mining operation. It is an important

factor when evaluating coal property because the larger the block size (i.e , the more coal that can be produced), the greater the potential revenue from the mine over its lifetime.

Reserve blocks are limited in size by topographical and geological constraints which affect the continuity and/or extent of the mineable portion of a seam. An example of such a constraint is in central Appalachia where steep ridges may contain numerous but small and isolated coal beds. Thus, a single ridge may contain a total of 30 mmt (million tons) of coal but have individual mines limited to 6 mmt tons of total possible production

In the EEA reserve characterization, four block sizes are considered for underground mining, 6 mmt, 20 mmt, 40 mmt, and 60 mmt Three block sizes are used to describe surface mines; 6 mmt, 20 mmt, and 150 mmt

Separate methodologies were used to assign block sizes to·

- o underground-mineable reserves in Appalachia
- o all other underground-mineable reserves
- o surface-mineable reserves

These methodologies are discussed below

6 5 8 2 Methodology for Appalachian Underground Reserves

In order to estimate the distribution of Appalachian underground reserves by block size, several assumptions had to be made. They are

- o Seam discontinuity due to non-deposition or washout phenomena is not considered to have an impact on block size
- o Mine blocks 50 feet below drainage are not restricted by surface topography or first or second order drainage

- o Coal allocated in the summary reports to overburden categories is distributed evenly throughout the category. Thus, if a summary report allocates 'x' tons of coal to the 0 to 1000 foot overburden categories, it is assumed that the 300 to 400 foot and 700 to 800 foot overburden ranges both contain 0 1(x).

Exceptions to all of these assumptions can be found in any specific area, however, when considering an entire county or state, the "averaging out" affect of a large area makes the assumptions generally hold. In addition, the reserve base used in this model includes inferred coal resources and this helps to balance the distribution of reserves between shallow and deep overburden within the 0-1000 feet category

6 5.8 2 1 Reserves Above Drainage

Coal reserves above drainage are those considered to be drift-mineable In Appalachia, reserves above drainage typically contain topographic constraints which limit the size of mines within those reserves to relatively small reserve block sizes, equivalent to the model block size categories of 6, 20, and 40 mmt. In order to estimate the constraints on block size for each of the groups of counties for which reserve totals were calculated, "model hills" typifying the average topography of each country group were developed. The effect of a model hill's topography as a constraint on mining block size was then calculated Separate calculations were made for thick and thin seam reserves

The methodology used to allocate Appalachian underground reserves above drainage to block sizes involved the following three steps:

1. Estimate average relief for each country group (i.e., the average change in elevation between drainage and the ridge-top)
2. Calculate the average base area for ridges in the county group
3. Given the average base, height, and slope (from Section 6.5.4), construct the model hill.

These steps are discussed in detail below.

6 5.8 1 1 1 Estimate Average Relief

The same groupings of counties used to classify surface reserves by slope were used to estimate distribution by block size The average relief was determined for each group of counties from relief measurements taken at the same location as the slope measurements

6 5.8 1 1 2 Calculate Average Base Area

The area at the base of the ridge where the slope and relief measurements were taken was measured with a planimeter on 1 24,000 USGS Quadrangle maps The base area was defined as the area between second or third order streams This area was considered the largest block size mineable in that ridge above drainage An average was taken of all the base area measurements to obtain a standard base area for the group of counties

6.5.8 1.1 3 Construction of the Model Hill

The average slope, relief and base area of ridges in a group of counties were used to construct a model hill from which estimates of block size distribution could be made The relief was used to estimate the percentage of coal in the 0-1000 feet overburden category that would be affected by surface topography For example, an average relief of 600 feet would indicate that 60 percent of the coal in the 0-1000 foot category would be contained in hillsides and would outcrop

Once the topographic characteristics of a model hill are known, the next step is to determine how many tons of coal a single seam can contain within a hill of this size This calculation is made at the base of the hill, as this is where the largest seam above drainage (in terms of area and thus tons of coal) could be located. Hence, this calculation serves as an estimate for the largest drift mine in the county group.

Separate calculations were made for thick and thin seams, since the county group represented by a model hill will contain reserves of both types Depending on the results of the calculation, the analysis could proceed in either of two directions

<u>Small Reserve Case</u> Twenty million tons was set as the cut-off for assigning reserves to the smallest block size category (6 mmt) Therefore, if the tonnage calculation for a seam thickness results in a reserve of 20 million tons or less, then all coal of that seam thickness estimated to be above drainage in that county group represented by the model hill is assigned to the small reserve block

<u>Large Reserve Case</u> If the base calculation produces a coal reserve greater than 20 mmt, then the coal above drainage in the county group had to be allocated among the larger reserve block sizes (i.e , 20 and 40 mmt). This was done by reference to the geometry of the country group's model hill, as illustrated by the following hypothetical example for a 60 inch seam

Assume the initial reserve calculation at the base of a 1000 foot high model hill produces a reserve of 80 mmt Given the base area and slope of the model hill, the elevation is calculated at which a perfectly horizontal seam 60 inches thick will encompass exactly 40 mmt of coal. Assume this is at an elevation of 400 feet Since the assumption is made that coal is evenly distributed through the 0 to 1000 foot overburden category (see Section 6 5 8 2), 40 percent* of the thick seam coal estimated for the county group to be in the 0-1000 foot overburden category is allocated to the 40 mmt reserve block

The next step is to calculate the elevation at which the 60 inch seam will produce a 20 mmt reserve (i e , the next largest block size).

*i.e., 400 ft - 1000 ft.

Assume that this is at 600 feet Twenty percent of the 0 to 1000 foot overburden category thick seam coal in the county group will then be assigned to the 20 MMT block size category * The remaining thick seam coal is then assigned to the 6 MMT reserve block This would be 40 percent of the total $(\frac{1000 \text{ feet} - 600 \text{ feet}}{1000 \text{ feet}})$

Additional detail on the methodology described by this example is presented in Appendix C

6 5 8 2 2 Reserves Beneath Drainage

Reserves beneath drainage were considered mineable by shaft mines only Coal reserves within a county group found 0-50 feet beneath drainage were assumed to be the same block size as in the base area of the appropriate model hill. This was done to account for the difficulty in mining directly under streams and/or valleys The amount of reserves allocated to this 50 foot interval was equal to 5 percent of the coal in the 0-1000 foot category. Again, this assumes that coal is evenly distributed throughout the 0-1000 foot category.

Reserves found more than 50 feet beneath drainage were characterized by the 40 mmt block size This large block size was used because reserves more than 50 feet below drainage, unlike those found above drainage and contained in hillsides, are not restricted in size by topography The impact of factors which might affect the continuity of these deeper reserves, such as areas of non-deposition or sand washouts, is impossible to estimate without a much more detailed study than is practical here. However, it is safe to assume that these factors would not limit mine size to the degree that topography does in the higher positioned reserves

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*(i e , $\frac{60 \text{ feet} - 400 \text{ feet}}{1000 \text{ feet}}$)

C-2

6.5.8 3 Methodology for Underground Reserves Outside of Appalachia

Outside of Appalachia, underground mine block size is generally not constrained by geological factors. Reserves are generally contained in either.

- broad, shallow basins containing continous coal seams under greatly rolling terrain and moderate overburden

- relatively deep and isolated coal basins characterized by moderate to steeply pitching seams Although seams outcrop, due to their pitch and mountainous terrain they rapidly become covered by thick overburden only a few hundred feet in from the outcrop

Block size is thus more a reflection of ownership patterns and economical mine size than geology

Block sizes were assigned to these resources as follows·

- The 20 mmt block size was assigned to thin seam reserves (28 to 41 inches).

- the 40 mmt block size was assigned to reserves 42 inches thick and greater.

The exception to the above criteria were steeply pitching and/or very deep reserves under more than 2000 feet of overburden. These geologic conditions generally dictate the use of longwall mining. Accordingly, longwall mines with a 60 mmt reserve block were assigned to these reserves The large size of the reserve block reflects the large scale of most longwall operations

6.5.8 4 Methodology for Surface Reserves

The distribution of surface reserves by block size was done primarily to distinguish the kinds of mining operations and mine sizes in various regions. Contour mines were characterized by small reserve blocks while area mines were characterized by the larger block sizes. Only one block size was considered for contour mines because even at the maximum economic

stripping ratio considered by the model (20.1), the bench width would still be so narrow that only a small mining operation could be supported This is a function of the relatively steep slopes and thin coal seams typical of Appalachian surface reserves.

Area surface-mining is used where seams are continuous and over broad areas under gently sloping terrain. These mines typically have larger reserves than Appalachian contour mines, since reserve block limits are more a function of mine economies, leasing and ownership constraints than geologic factors

Area mines in the Powder River Basin and northern Great Plains lignite fields, regions typified by large mining operations, were assigned the largest block size (150 MMT) if the reserve seam thickness was estimated at 42 inches or greater. This reflects the near ideal mining conditions often found in these regions: low stripping ratios, minimal slope, coal properties held in large blocks, and relatively few constraints from public land use (such as a pond overlaying the reserve). In the other western surface reserves, where conditions are generally not as favorable, the 150 mmt reserve block was assigned only to the reserve wth seams more than 119 inches thick. Otherwise the 20 mmt block size was used

6 5 9 Step 9 - Estimate Whether Underground Reserve Blocks are Drift or Shaft Mineable

Underground mines were further classified as being either drift or shaft mineable. In Appalachia and other areas of high relief, reserves that outcrop are drift mineable and those under drainage were classified as shaft mineable This distribution again assumed that reserves were evenly distributed within overburden categories and that a region having an average relief of 600 feet would have 60 percent of the 0-1000 feet overburden coal outcropping in hillsides

No attempt was made to estimate reserves that are slope mineable. However, slope mines that are below drainage have associated costs similar to shaft mines and are thus classified as such Mines above drainage that might have slope entries are included in the reserve description as drift mines

In western areas of low relief, where surface mining can prepare deeper seams for drift operations, the average seam pitch was used to calculate the maximum depth that could be drift mined Maximum distance from entrance was assumed to be three miles; thus, by multiplying this distance by the tangent of the average pitch, the additional depth that could be drift mined was determined For example, a maximum stripping ratio of 20.1 in Illinois would allow 100 feet of overburden to be removed for a five foot seam If the average pitch was 1 5 degrees, then the depth that could be drift mined would be approximated as (tangent (1.5) x 15,840 feet) + 105 feet = 519 feet

6.5 10 Step 10 - Distribution to Mine Types

The previous nine steps described how the total reserves were allocated to each category of the nine parameters included in the reserve characterization The next step was to calculate the percentage of reserves which is described by each combination (or mine type) of the nine parameters This was done by multiplying the percentages allotted to each parameter together in the different logical combinations This procedure resulted in the calculation of the percentage of total reserves allocated to each combination of parameters (or mine types).

6.5 11 Step 11 - Distribution of Mine Types Into Sulfur Categories

After the reserves had been allocated to mine types through the methods discussed in the previous ten steps, they were further classified according to sulfur content. It was assumed that the sulfur distribution was random for each region such that each mine type would have the same

proportion of compliance, low and high sulfur reserves allocated to it The percentage distributions in Table 6-1 were used to divide the mine types up into sulfur categories If this division resulted in allocating a portion of the reserves that was smaller than the smallest reserve block size, then that portion of the reserves would be added to the next highest sulfur category In this way, the creation of rare mine types with small reserves of low or compliance coal was avoided

6 6 EEA COAL MODEL RESERVE BASE

Table 6-3 summarizes the reserve data used in the EEA Coal Model The data includes measured, indicated and inferred coal resources.

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TABLE 6-3

RESERVES BY MINING METHOD

SUPPLY REGION	SURFACE	UNDERGROUND
1	6,398	22,844
2	6,932	50,819
3	13,250	44,136
4	383	2,727
5	29,148	86,000
6	6,398	4,150
7	752	1,902
8	10,829	--
9	39,059	--
10	33,213	69,200
11	20,664	74,057
12	5,324	8,622
13	2,327	64,508
14	1,596	33,563
15	9,848	204,151

SOURCES. see Section 6 7

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7. MINING COST

7.1 INTRODUCTION

This section of the report will describe the derivation of the mining costs used in the EEA coal model The discussion is divided into three parts:

(1) a review of current mining technology,

(2) a description of the mine cost models,

(3) a description of how mine cost ranges were used in the model

7.2 REVIEW OF CURRENT MINING TECHNOLOGIES

7 2 1 Underground Mining

In 1976, underground mining accounted for 43 percent of bituminous coal and lignite production Two mining methods accounted for almost all of this production room and pillar mining and longwall mining Following a general description of deep mines, these methods are described below

7 2 1.1 General Characteristics of Underground Mines

Development of an underground mine begins with preparatory work on the surface, such as construction of access roads and a coal preparation plant The actual entries into the coal-bearing formation can take one of three forms; these define the general category into which the mine falls

- <u>Drift Mines</u> are generally the preferred type of underground operation, and are the predominant type of deep mine. In this case, horizontal or nearly horizontal entries are driven into a coal outcrop on a mountain or hillside This is the least expensive kind of mine to develop, since there is no need to cut through overburden before reaching the coal deposit.

- Shaft Mines involve sinking concrete-lined vertical shafts, in some cases through over 2000 feet of overburden, in order to reach the coal seams. This method entails higher development costs than for drift mines, as well as additional capital investment for such items as shaft hoisting equipment

- Slope Mines are characterized by angled shafts cut through a pitching coal seam or overburden down to the major coal deposit Slope mine costs lie between those of drift and shaft mines. As was noted earlier, the model does not explicitly include slope mines Slope mineable reserve blocks are placed in either the drift or shaft mine categories (see Section 6 5 9)

Coal, men, and material can be moved through a mine by conveyors, electric shuttle cars, and small electric locomotives which pull cars on tractors In shaft mines a hoist must be used to move between the mine and the surface Once at the surface, the "run-of-the-mine" coal generally moves through a preparation plant for crushing, screening, and washing before shipment Washing removes impurities from the coal, increasing its heat value and reducing the quantity of pollutants it releases when burned

7.2 1.2 Room and Pillar Mining

Irrespective of whether a mine is developed as a drift, shaft, or slope operation, the method used to remove the coal is usually via room and pillar mining This method accounted for about 96 percent of U S underground coal production in 1976, and is likely to remain the predominant method used through the end of the century.

In room and pillar mining, several (typically three to eight) parallel main headings are driven into the coal seam. By driving submains at a 90° angle from the main headings, and then 90° angle cuts from the submains, the coal is systematically mined out, leaving a checker-board pattern of coal pillars to support the mine roof. The size of the pillars depends on the stability of the mine roof, ribs (walls), and floor, which in turn are largely a function of the composition of the

surrounding strata and the depth of the mine The less stable the mine is, the larger the pillars must be.

Once the mine has been fully developed, retreat mining begins In this process the miners work back toward the mine entrance, removing as much of the coal pillars as is safe As the miners retreat the mine is allowed to collapse in back of them Retreat mining is essential to maximizing coal recovery, but if roof conditions are particularly bad, or if surface subsidence must be limited, only a small portion or none of the pillars will be removed In a typical mine, the combination of initial and retreat mining will recover about 50% of the available coal in the mined area

One of two techniques is generally used to actually remove the coal Conventional mining accounted for 33 percent of deep mine production in 1976. In this system, a large chain-saw is used to undercut the coal face A drill is then brought in to cut holes for explosives, which are detonated to fragment the coal. An automated loader is then used to move the coal to conveyors or a shuttle car

The conventional mining system requires relatively little capital investment (less than $200,000 for all three machines), but needs a well-trained and coordinated crew for efficient and economical operation Over the last 30 years, conventional mining has largely been replaced by continuous mining, which in 1976 accounted for 63 percent of deep mine production The continuous miner, which essentially combines the conventional mining functions into one piece of machinery, consists of a rotating cutting head mounted on a mobile platform As the continuous miner moves forward, coal is cut from the seam and allowed to fall onto the unit's built-in conveyors for transport to shuttle cars or the main conveyor system Although this system is highly automated, the term "continuous" is something of a misnomer, since the miner must frequently stop to allow roof bolting in the mined area, methane checks, and the advancement of ventilation equipment.

Compared to conventional mining, the continous miner offers simplicity and the potential for greater productivity Between 1959 and 1974, the percent of deep mine production accounted for by continuous miners rose from 23 2 percent to 61 8 percent But over the next two years, the continuous miner proportion rose to only 63 percent, and is believed to be essentially unchanged today [1/] The reasons for the lack of continued growth in the use of continuous mining, and the complementary stabilization in the share of production accounted for by conventional mining, are not entirely clear, but at least three factors appear to be of importance.

- o Some of the potential growth in the use of continuous miners has been pre-empted by longwall systems (described below)
- o High interest rates through the 1970's may have encouraged the use of relatively low investment cost and labor intensive conventional mining systems in place of high investment cost (over $350,000 per unit) continuous mining
- o Relatively small deep mines have grown in number and importance through the 1970's and they may prefer the lower capital investment conventional system (see Section 7 3 2 2.1)

7.2 1 3 Longwall Mining

In 1976, about 4 percent of underground mine production was accouted for by longwall mining (compared to room and pillar's 96 percent). Although widely used in Europe, longwall systems have seen significant use in the U S only over the past decade

A typical longwall mine face is developed by driving with continuous miners two parallel sets of main headings, about 450 feet apart and 2500 feet long, into the coal seam The headings are interconnected at their ends and the longwall equipment installed This consists of 1) a cutting head which is pulled by a "face conveyor" back and forth across the entire length of the working face; 2) a belt conveyor to catch the cut coal and transport it away, and 3) a series of self-advancing shields

which support the roof. As the coal is cut, the cutting apparatus, conveyor, and shields progress back toward the mine entrance, while the mine roof is allowed to collapse behind the advancing shields

The longwall system has many advantages over continuous or conventional room and pillar mining. It requires less labor, is safer (the crew is always under the protection of the roof shields), and can be tremendously productive· where a room and pillar mine might produce 10-20 tons of coal per person-day, a longwall mine can produce 30-40 tons per person-day or better. Longwall systems can be used to efficiently mine steeply pitching coal seams, something which room and pillar techniques cannot do

These many advantages, and the great success longwall mining has had in Europe, led to predictions that longwall mining would account for as much as 25 percent of American deep mine production by the mid-1980's. However, these projections now appear to have been optimistic, one recent analysis estimated longwall's share of underground production at only 12 percent by 1985 [2/] The same study notes several reasons for a more pessimistic outlook:

- To use the longwall system, U.S mining engineers and managers will have to adapt to methods very different from those they have been used to. In particular, longwall mining requires much more detailed planning and disciplined operations than the highly flexible room and pillar approach

- U.S. safety regulations require the development of multiple entries (for haulage, ventilation, and other logistics) along the two main headings which define the perimeter of the area to be longwall mined. This requirement, which contrasts with European practice that permits single entries, greatly increases the development work which must be completed before the longwall unit can be put in operation. (The development lead-time can be as long as three years.) As a result, a longwall system can often mine-out an area faster than additional areas can be developed, resulting in excessive idle-time for the very expensive longwall equipment.

- In West Germany, longwall mines have been used very successfully to mine thin coal seams (less than one meter thick). However, in the U.S geological and regulatory constraints make this application look much less promising

An additional factor may be high interest rates, which may have deterred firms from making the enormous capital investment (over $1 million) a longwall system requires

7.2.2 Surface Mining

Surface mining is the major coal mining method in the U.S , accounting for 57 percent of production in 1976. The two basic types of surface mining, contour and area mining, are discussed below.

7.2.2.1 Contour Mining

Contour mining is practiced almost exclusively in Appalachia In a typical operation, an access road is built up to a coal outcrop on a hillside A bench is then cut into the hillside in order to expose the coal. Several kinds of earthmoving equipment can be used to remove the overburden and coal, including bulldozers, front-end loaders, and small draglines Explosives are also used frequently to fragment the overburden before removal.

The bench is cut into the hillside until the stripping ratio - that is, the ratio of overburden removed to coal removed - becomes uneconomical A new section of bench is then cut further along the hillside, eventually creating a continuous cut along the hill on the elevation of the coal outcrop. To recover additional coal once the maximum economical stripping ratio has been reached, an auger miner (essentially a giant drill) may be used to extract coal from under the highwall A contour mine can generally expect to recover 70-90 percent of the available coal. As in the case of underground mines, the coal is transported to a preparation plant (usually by truck)

A variant of contour mining is mountaintop removal In this case, used when the coal seam is close to the top of a hill, the entire hilltop is removed to expose the coal This technique is not used frequently

Contour mining can cause severe environmental problems. Unless controlled, the displaced overburden or "spoil" can cause landslides, erosion, and silting of stream Acid runoff from the exposed hillside can pollute water And the long contour-mined benches, running along hundreds of feet of mountainside, can ruin the aesthetic value of an area. State and federal regulations require various steps to be taken in order to prevent environmental damage while mining is in progress and to reclaim the land afterwards In particular, the federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) requires that the land be reclaimed to an approximation of the original contour (AOC) which existed before mining began

7.2.2.2 Area Mining

Area mining is used to extract coal from surface mineable reserves located under level terrain Planning and surface development for a large western area mine can take up to five years. In a typical operation, overburden will be removed sequentially in a series of long parallel strips, perhaps 100 feet wide by a mile long The overburden is first fragmented by explosives, then removed by a dragline The surface of the exposed coal seam is then scraped clean, the coal fragmented with explosives, and removed by front-end loaders and trucks When seams are very thick and the stripping ratio favorable, power shovels and trucks may be used in place of draglines to remove the overburden. In this case, much wider areas, perhaps 1000-2000 feet wide, are developed simultaneously instead of the narrow strips The low-sulfur western coal typically mined by area methods is often only crushed in the preparation plant and does not require washing before shipment. As in the case of contour mines, area-mined lands must be reclaimed to an approximation of the original contour.

7 3 DEVELOPMENT OF THE MINE COST MODELS

This section will describe how mine cost models were developed to reflect the mining technologies described above After a general overview of the methodology, the underground, contour, and area mine models are described

7 3 1 Methodology Overview

As described in Section B.2, each coal reserve block is defined by a numeric code which identifies its geologic characteristics, size, and the mining method which will be applied to it The mine cost models use this information as well as the year of the model run (1985 or 2000) and the supply region location of a reserve to assign a production cost to each reserve block.

Mine models were developed for underground, contour, and area coal mining. In each case the models were designed to reflect the cost impact of the following factors·

- Mine size - the method for assigning a base mine size to a reserve block is shown in Table 7-1
- Geologic conditions, especially seam thickness
- Royalty rates and severance taxes (Table 7-2)
- The impact of government regulation, especially reclamation requirements

In all cases, the model produces a minimum acceptable selling price (MASP) for a ton of coal, expressed in 1979 dollars. This is a price high enough to recover all costs plus a 15 percent return on investment

The initial output from the mine models assigns a single MASP to each reserve block in the coal reserve characterization. In reality, mining cost vary widely, even for mines of the same size working similar (or even the same) reserves. To reflect these circumstances, the final

TABLE 7-1

ASSIGNMENT OF BASE MINE SIZES TO RESERVE BLOCK SIZES

Reserve Block Size Categories (millions of tons)	Mine Model Base Sizes (millions of tons)				
	Area	Contour	Longwall	Room & Pillar	Room & Pillar-Thin Seam
1 (6)	27	15	n/a	15	.125
2 (20)	90	.15	n/a	50	.250
3 (40)	1 80	.15	1.50	1.00	.250
4 (60)	2 7	n/a	1 50	n/a	n/a
5 (150)	6 75	n/a	1.50	n/a	n/a

Notes:
- o Area Mines· base mine size is determined by dividing the number of tons assigned to reserve block category by 20 years, then multiplying by a 90 year recovery factor
- o Contour Mines: are fixed at a typical size, 150,000 tons/year
- o Longwall Mines. are fixed at a typical size, 1 5 million tons per year
- o Room and Pillar are calculated as in (1), except using a recovery rate of 50 percent
- o Room and Pillar - thin seam are fixed at typical sizes, 125,000 and 250,000 tons per year

n/a = not applicable

TABLE 7-2

SEVERANCE TAX AND ROYALTY RATES

Supply Region	Severance Tax Rate	Royalty Rate
1	0	05
2	.0385	.05
3	.045	.05
4	0	.05
5	045	.05
6	05	.05
7	0	14
8	0	14
9	3	.14
10	3	14
11	02	14
12	02	.14
13	02	14
14	02	14
15	0	.14

SOURCE: Energy Information Administration, National Coal Model--Coal Supply Curves, EEA estimates.

costing calculation includes a high, medium, and low cost spread for each reserve block These calculations are derived from the base costs and better represent actual industry conditions than simply one cost figure.

Two different approaches were taken in developing the models. The underground mine model was developed essentially from scratch, using DOE and Bureau of Mines (BOM) data for the basic cost information. In contrast, the surface mine models used are adaptions from earlier models The contour mine model is based on a Oak Ridge National Laboratory (ORNL) model, and the area mine model is adapted from work done for the Energy Research and Development Administration In both cases the earlier models were adjusted to reflect 1979 costs and the return on investment criteria set for the JPL project.

All three models share several common characteristics Most important are the following four assumptions:

1) The models are designed to reflect 1979 mining technologies, which are not varied through 2000 This is a reasonable approach, since no major improvements in technology appear to be in the offing. Even if a major advance did take place, it would likely take years to be widely accepted and introduced to the mines, much as with longwall systems.

2) Mine capital and operating costs are not projected to increase in real terms through 1985. Through 2000, labor costs are projected to increase in real terms by 20 percent. This reflects a long term trend in which labor cost increases have exceeded capital cost increases by an average of 1 percent annually.

3) Legislation and regulations affecting coal mining in 1979 are assumed unchanged through 2000. The royalty, income tax, and severance tax rates in effect in 1979 and the 10 percent federal investment tax credit are all held constant.

4) The United Mine Workers of America (UMW) is not projected to increase its influence beyond those portions of the country where it is currently a major force. This assumption, which has implications for labor costs, reflects the difficulties

the UMW has had for many years in recruiting new members, especially in new western mines

7.3.2 Underground Mine Model

The underground mine model is the most detailed of the three mine cost models Its operation consists of three interrelated steps.

1) For a given mine type (drift vs shaft, room and pillar vs longwall) and base production size, inputs covering capital, and operating costs are fed into the model Other cost elements, such as depreciation, are calculated internally, while some are dependent on the productivity determination made in step 2.

2) The mine's production level and costs are adjusted to reflect the mine's estimated productivity (measured in tons of uncleaned coal per worker-day) The productivity estimate depends on the mine's base size, geologic characteristics, and supply region.

3) Once all the costs are set, calculations are made to determine the amount of annual revenue required to cover all costs, including the severance tax and royalty rates applicable to each supply region, plus a 15 percent return on investment The annual revenue requirement is then divided by the clean tonnage produced by the mine to determine the minimum acceptable selling price per ton

Several types and sizes of mines are covered by the model, including.

- Room and pillar mines, with base production levels of 150,000 500,000, and 1 million tons per year These may be either drift or shaft mines All use continuous miners. This is a simplification since many deep mines use conventional mining techniques. However, since the total costs of continuous and conventional mining are similiar--the former has relatively lower operating costs and the latter lower capital costs--this is a reasonable approach

- Room and pillar mines utilizing continuous haulage, a system in which a special conveyor is linked with the continuous miner in order to speed coal movement out of the mine. Reflecting actual practice, this mining system is assigned only to thin seams (28-42 inches) and pre-empts all other room and pillar mines in these seams. These mines have base sizes of 125,000 and 250,000 tons per year, and can be either drift or shaft.

- Longwall mines with a base production of 1.5 million tons per year These can be either drift or shaft mines

The next three sections will discuss the costing portion of the model, the productivity estimation method, and the revenue calculations The model data inputs and the model outline are presented in Section 7 3.2.4

7.3 2 1 Financial Structure and Components

The financial structure and cost data inputs for the deep mine model were derived primarily from DOE and BOM studies of typical mine costs [3/] The capital and operating costs presented in these studies were inflated to 1979 levels. All costs were held constant through 1985 Through 2000, all labor costs were increased 20 percent to reflect a long-term trend in which labor cost increases have exceeded capital cost increases by an annual average of 1 percent

Capital costs included:

- Costs incurred in developing the mine to the point where it achieves full production This includes some capitalized expenses, such as exploration, and includes a credit for coal produced during development

- All other initial investment, including the mining, haulage, and support equipment and facilities needed to operate the mine.

- The present value (1979 dollars) of deferred investment, such as replacement of worn out continuous miners

In addition to the input capital costs, special capital investment adjustments are made by the model to reflect the costs of a hoist, main shaft, and ventilation shafts for shaft mines It also adjusts development costs downward for longwall mines in thin seams Depreciation, working capital, taxes, and insurance are all calculated by the model as percentages of total initial investment using factors derived from the DOE and BOM studies.

Operating costs entered as direct data inputs included.

- o Direct labor. Labor overhead is calculated within the model as 40 percent of direct labor, following the BOM and DOE methodology.
- o Operating supplies, such as roof bolts.
- o Power and water.
- o Other operating expenses, including the mine reclamation fund and licenses.

Operating supply costs are taken to be directly proportional to mine output. Therefore, they are recalculated by the model from the base level according to the change in production caused by the productivity adjustment. Indirect costs are taken as a fixed 15 percent of operating supply and direct labor costs following the BOM and DOE methodologies

Union welfare costs and coal cleaning costs are directly dependent on the final mine production value, as developed from the productivity adjustment. Union welfare costs under the current UMW contract equal.

1) $2.05 per ton of uncleaned coal, plus . . .

2) $0.94 per hour worked. The number of hours worked in a mine is calculated from input data on the number of union employees in each mine and an assumed 8 hour day, 220 working days per year.

Note that union welfare costs are not included for mines in supply regions 3 and 7 through 15, since mines in these areas are generally non-union. Cleaning costs are $1.75 per raw ton, reflecting a refuse rate of 15 percent. This is estimated to be a fair national average

7.3.2.2 Productivity

The productivity estimate assigned to a particular mine is the major factor in determining its MASP. This is because mine costs, with the

exception of some operating and labor costs, are fixed for a given mine base size and type The productivity estimate thus becomes critical because it determines the total coal production and thus the number of tons of coal costs can be spread over Therefore, holding all other factors constant, the MASP for a mine will vary inversely with productivity

The productivity estimates were developed through a four step process:

- o A base productivity figure was calculated. This was done differently for longwall, Appalachian room and pillar, and all other room and pillar mines
- o The productivity figures for mines were adjusted for geological factors.
- o The productivity figures were adjusted to reflect raw (uncleaned) production.
- o A final adjustment was made to reflect expected gains in productivity through 2000

These steps are described below Except as noted, all productivity data used in the calculations were taken on a mine-by-mine basis from Mine Safety and Health Administration (MSHA) statistics covering over 1600 underground mines for the period first quarter 1978 to first quarter 1979 [4/]

7.3.2.2.1 Step 1 - Base Productivity Calculations

Longwall Mines

The base productivity figure for longwall mines was taken from the BOM study, with two modifications. BOM estimated only 20 major maintenance shifts per year for a longwall unit. This appeared very optimistic and was increased to 60 shifts. BOM also assumed that the continuous miner units used for development work in a longwall mine could produce 340 tons per machine shift. This was reduced to a more realistic 300 TPMS The overall effect was to reduce the base productivity from 33.8 tons/person-day to 30.9 tons/person-day.

Room and Pillar Mines Outside Appalachia

For the Illinois basin (supply region 5) productivity figures were taken for a random sample of 36 mines from the Mine Safety and Health Administration data Each mine's annual production was also noted and used to calculate a regional weighted average productivity as follows:

$$P = \sum_{i=1}^{36} \frac{T_i P_i}{T}$$

where:
- P = weighted average productivity
- T_i = annual production for mine i
- P_i = productivity for mine i
- T = total production for all 36 mines

This yields a productivity figure of 13 6 tons per worker-day

For the remaining western supply regions (7-15) a similar procedure was used. The 21 mines used in the calculation represent a sample from the major western underground mining states of Utah, Colorado, and New Mexico. The resulting average productivity was 18 2 tons per worker-day

Appalachia

In Appalachia, the base productivities for the mines reflect an inverse relationship in this region between mine size and productivity, i.e., diseconomies of scale This relationship is believed to be the result of a number of l..bor- and managerial-related factors

- Smaller mines are likely to have a more cohesive work force than relatively large operations. This is of central importance, since teamwork is a critical element in efficient mining operations.

- Relatively small mines tend to be non-union, and non-union mines tend to suffer less from labor disruption and to be more productive than union operations

- In smaller mines, union or not, management tends to be closer to labor than in relatively larger mines, producing better labor-relations

- Smaller mines tend to have older and more experienced - and thus more productive - workers.

The major implication of these points is that smaller mines, with advantages in labor and management efficiency, can be more productive and thus more economical than larger operations There is, in fact, evidence showing that small underground mines have been increasing their share of total underground production through the 1970's (see Table 7-3).

In order to quantify this inverse relationship between mine size and productivity, a linear regression analysis was performed between mine size, represented by the average number of workers employed daily, and productivity for samples of mines from each of the four Appalachian supply regions. The results from the analysis are presented in Table 7-4 As expected, the slope and r statistics are in all cases negative, indicating an inverse relationship between the variables. The r^2 statistics are low, at best only 199 This was expected, since productivity is affected by a variety of interrelated labor, management, geological, and regulatory factors

Given the consistency in the inverse relationship seen across the supply regions, it seemed reasonable to use these results to estimate deep mine productivity for Appalachia room and pillar deep mines The following formula was used for the estimations.

$$P_{ni} = a_n + b_n s_i$$

where: P = productivity
n = supply regions 1-4
i = base mine size (in tons produced annually) as presented in the DOE and BOM cost analyses for room and pillar mines
b = slope
s = the number of men estimated in the DOE and BOM reports for a mine size base mine
a = the y intercept

The input values for these equations can be found in Tables 7-2, 7-4, and in Section 7.3.2.4.

TABLE 7-3

PRODUCTION SHARE OF SMALL UNDERGROUND MINES[1/]

	Small Underground Mines as a Percentage of all Deep Mines	Small Underground Mine Production (as a Share of Total Deep Mine Production)
1972	66%	8%
1976	71%	13%
1978	81%	20%

1/ Annual Production of 100,000 tons or less

SOURCE Mines Safety and Health Administration, Injury Experience in Coal Mining, 1972, 1976, 1978

TABLE 7-4

PRODUCTIVITY ANALYSIS RESULTS

Supply Region					Productivity		Men Employed Daily	
(n)	r	r^2	Slope	Y Intercept	Mean	Stnd Dev.	Mean	Stnd Dev
1 (27)	- 477	.199	- 01	12 2	9 4	5.1	228	225
2 (126)	-.311	.097	-.015	13.2	11 3	7 3	123	147
3 (207)	- 323	105	- 046	15 4	13 8	8 6	33	60
4 (33)	- 210	.044	-.077	8 6	8.6	5.4	146	166

Note: Statistics are significant at the 90 percent confidence level

SOURCE. Coal Outlook Productivity Report, October 26, 1979, EEA estimates

7.3 2 2.2 Step 2 - Geologic Condition-Related

Mine productivity is, of course, heavily dependent on the geologic characteristics of the area being mined. Geologic factors were taken into account by the underground mine model in three ways. First, all reserves with seams pitching more than 30° were assigned to longwall mines Ordinary room and pillar techniques have great difficulty dealing with such conditions, while longwall units are very adaptable to steeply pitching seams

Second, the base productivity of longwall mines in thin seams (28-41 inches) was cut in half. This is only a rough estimate. There is little U S experience with longwalls in these conditions on which to base estimates, and European experiences are not directly applicable because European thin seam mining generally takes place in more favorable geologic circumstances than in the U.S

Finally, the base productivity for all room and pillar mines was adjusted by seam thickness The following methodology was employed to make these adjustments.

- First, average seam thicknesses were determined for each supply region. This was done by selecting a sample of mines from the MSHA data and then cross-indexing with the mine profiles presented in the 1979 Keystone Coal Industry Manual to determine the thickness of the seam a mine was exploiting Each seam thickness was then weighted by its mine's production to produce a weighted average seam thickness for the supply region.

  For supply regions 6-15, the results for the major western underground mining states of Utah, Colorado, and New Mexico were applied to all the regions Individual calculations were made for supply regions 1-5.

- Second, the differences between the regional average seam thicknesses and the EEA model seam thickness categories were calculated. For example, the EEA seam thickness category 1 is 28 to 41 inches, the midpoint of which is 35 inches. For supply region 1 (Ohio) the regional seam thickness was 56

inches. The difference was 35-56 = -21 Similar calculations were for made for such EEA seam thickness category for each supply region

- Given the differences between the regional seam thicknesses and the EEA seam thickness categories, the base productivity for each room and pillar mine was adjusted using the following equation:

  $$P'_{mi} = P_{mi} + S(D_{mij})$$

  where.
  - m = supply regions 1-15
  - i = base mine size (in annual tons of production) as presented in the DOE and BOM cost analyses for room and pillar mines
  - P = base productivity for a mine
  - P' = P adjusted for seam thickness
  - S = 11
  - D = an EEA seam thickness category minus the average seam thickness for a region.
  - j = EEA model seam thickness categories 1, 2, and 3 The values assigned to the ranges each category represents were, respectively, 55, 81, and 120 inches.

The key to the equation is the value of S, i e , the amount productivity goes up or down for each one inch variation in seam thickness The ICF coal model and DOE's similar National Coal Model estimate that productivity varies by .083 tons per worker-day for each one inch variation An EEA linear regression analysis between seam thickness and mine productivity, using the MSHA data described previously, indicated that a somewhat higher value of S = .11 would be more appropriate, and this value was used.

7.3.2.2 3 Step 3 - Coal Cleaning Adjustment

The productivity data used in all the above calculations are based on DOE and BOM figures derived from cleaned coal production figures. For the purposes of the model productivity had to be on an uncleaned coal basis, since several cost functions are calculated in terms of raw production tonnage.

Productivity calculations based on raw tonnage will be higher than those based on clean tonnage To bring the productivity figures calculated in Step 2 up to a raw tonnage basis, correction factors for each supply region were calculated as follows

$$PRODFAC_m = \frac{1}{1-(cc_m - cn_m)}$$

where m = supply regions 1, 2, 3, 4, 5, 6, and 7 to 15 combined
PRODFAC = The factor multiplied times all mine productivities in a supply region to bring them to a raw tonnage basis
cc = fraction of coal in a supply region which is cleaned
cn = fraction of cleaned coal which is reject

7.3.2 2.4 Step 4 - Productivity Increases Through 2000

After having declined from 1969 to 1977, productivity in underground coal mines has begun to increase once again. From a low of 8 7 tons per worker-day in 1977, productivity in 1978 appears to have been in the area of 10 3 tons and in 1979 about 10 9 tons. This is an increase of 25 percent from 1977 to 1979.[5/]

The upward trend appears likely to continue, since many of the factors which caused productivity to decline from its 1969 peak of 15 6 tons per worker-day have been moderated. After years of unrest, the deep mine work force has begun to stabilize in terms of age, experience, and labor relations It is particularly notable that labor stoppages (in all coal mines nationwide) declined from about 1400 in 1976 to only 275 in 1978. The federal mine safety and health regulations which, when first introduced in 1969, had a significant impact on productivity have now been integrated into mine operations. Similarly, UMW work rule changes which reduced productivity in the mid-1970's have now become a routine part of mine operations.

Given these circumstances, it appeared reasonable to assume that productivity would continue to increase past 1979 levels Just how large that

increase will be is speculative; therefore, moderate values were used in the EEA model. Specifically, all the productivities calculated in Step 3 are increased by five percent for 1985 model runs and by 20 percent for 2000 runs

7.3.2 2.5 Summary

The final result of steps 1 to 4 is an individual productivity figure for each base size mine, by supply region, seam thickness, and year The productivity figure is then multiplied by 220 working days per year and the estimated number of mine employees to produce a new annual production level for the mine.

7.3.2.3 Revenue Calculation

The model develops total capital, operating, and depreciation costs from the input data and internal calculations based on productivity and geologic conditions. To estimate the revenue required to recover all cost plus a 15 percent return on investment, a two-step procedure was employed

First, cash flow, the final cost-related element needed for the revenue calculation must be derived. This is done by multiplying the sum of all capital investment expenditures by $\frac{1}{6.533}$; the uniform present worth factor for a 15 percent return over a 20 year life, adjusted to reflect a ten percent federal investment tax credit Once cash flow is known, the final revenue computation is made, based on a marginal income tax rate of 50 percent and the severance tax and royalty rates applicable to a given region. (The actual formula used in the calculations are presented at the end of the model outline, Table 7-8.) The MASP for a ton of coal then equals the annual revenue requirement divided by the mine's annual production of clean tonnage.

7.3.2.4 Deep Mine Model Data Inputs and Outline

Tables 7-2, 7-5, 7-6, and 7-7 present the data inputs for the deep mine model Table 7-8 presents the model itself.

TABLE 7-5

PRODUCTIVITY INPUTS FOR DEEP MINES
(tons of cleaned coal per person-day)

Mine Type and Block Size	Supply Regions 1	2	3	4	5	6	7-15	Seam Thickness Category
Room & Pillar	12.2	9.1	4.1	9.5	14.4	14.4	12.3	2
3	16.4	13.4	8.3	13.8	18.7	18.7	16.6	3
Room & Pillar	13.4	10.8	9.5	10.3	14.4	14.4	12.3	2
2	17.6	15.1	13.7	14.6	18.7	18.7	16.6	3
Room & Pillar	14.3	12.3	14.0	11.0	14.4	14.4	12.3	2
1	18.5	16.6	18.2	15.3	18.7	18.7	16.6	3
Room & Pillar Thin Seam 1	9.6	7.9	10.7	6.2	9.3	9.3	7.2	1
Room & Pillar Thin Seam 2 & 3	9.5	7.7	10.0	6.1	9.3	9.3	7.2	1
Longwall	15.6	15.6	15.6	15.6	15.6	15.6	15.6	1
3,4, & 5	31.2	31.2	31.2	31.2	31.2	31.2	31.2	2, 3

SOURCE: EEA estimates

TABLE 7-6

PRODUCTIVITY PRODUCTION FACTORS FOR DEEP MINES[1/]

Supply Region	Factor
1	1.25
2	1.35
3	1.20
4	1.70
5	1.16
6	1.16
7 to 15	1.09

1/ Used to bring the productivity figures in Table 7-5 up to a raw tonnage basis

SOURCE: EEA estimates

TABLE 7-7

BASE MINE COST, PRODUCTION, AND MANNING INPUTS FOR DEEP MINES
(all costs in millions of 1979 dollars)

Mine Code
(see over)

Capital Costs:

Mine Code	Development	Deferred	Other Initial
1	15.7	4.5	24.3
2	9.5	2.9	16.6
3	2.7	1.3	6.0
4	0	0.1	4.5
5	0	0.3	2.6
6	9.2	5.8	33.8

Operating Costs:

Mine Code	Direct Labor		Operating Supplies	Power and Water
	1985	2000		
1	4.7	5.6	2.8	0.6
2	2.9	3.5	1.3	0.4
3	1.1	1.3	0.4	0.1
4	0.8	1.0	0.5	0.04
5	0.6	0.7	0.3	0.03
6	3.8	4.5	4.0	0.4

Mine Code	Other
1	0.4
2	1.0
3	0
4	0
5	0
6	0.5

TABLE 7-7
(continued)

Mine Code

Misc. Items:

Mine Code	Total Employees	Union Employees	Base Production
1	283	250	1,000,000
2	165	129	500,000
3	67	49	150,000
4	43	36	250,000
5	28	23	125,000
6	202	161	1,500,000

Key.

1 Room & Pillar, 1.0 million tons/year

2 Room & Pillar; 500,000 tons/year

3 Room & Pillar; 150,000 tons/year

4 Room & Pillar; thin seam; 250,000 tons/year

5 Room & Pillar, thin seam; 125,000 tons/year

6 Longwall; 1.5 million tons/year

SOURCE. BOM, Information Circular 8715, DOE, Economic Analysis of Coal Mining Costs for Underground and Strip Mining Operations; EEA estimates.

TABLE 7-8

DEEP MINE MODEL

I. Model Summary

The model consists of four main segments. These are

A Productivity and Production Calculations in this section a productivity figure is selected for a mine, depending on its location, geological characteristics, and year of the model run. This new productivity figure is used to recalculate annual mine production.

B. Capital Investment. capital investment costs are calculated from input data or internal computations

C. Operating Costs· operating costs are calculated from input data or internal computations

D. Revenue Calculation. based on the costs and production levels set in the earlier steps, the revenue required to recover all costs plus a 15 percent return on investment is determined Several final tax adjustments are made in this segment

All the input data for the model can be found in Tables 7-2, 7-5, 7-6, and 7-7.

II. Model Outline

A. Productivity and Production Calculations

1. Given region and geology, select productivity (PROD) from matrix (Table 7-5)

a) For all mines except longwall

PROD in 1985 equals PROD x 1.05

PROD in 2000 equals PROD x 1 20

b) For longwall mines in sharply pitching (category 3) seams PROD = PROD ÷ 2

c) Select clean tonnage correction factor (PRODFAC) for the region

d) PROD = PROD x PRODFAC

TABLE 7-8 (Cont'd)

DEEP MINE MODEL

2. Raw production tons (RAW) = PROD x 220 days x number of men (NUMMEN)

3. Clean tonnage (CLEAN) = RAW x .85

4. Cleaning Costs (CLNCOST) = RAW x \$1.75

5. Union Welfare (WELF)[1/] =

   (RAW x \$2.05) + (UMWMEN)[2/] (8 hours) (220 days) (\$0.94)

B. <u>Capital Investment</u>

1. Input data·
   - o Development Cost (DEVEL)
   - o Other Initial (OTHRI)
   - o Present Value of Deferred Investment (DEFRI)

2. Shaft Mine Adjustment

   a) Shaft OTHRI = OTHRI + (overburden depth in feet[3/] x \$4400) + \$666,000

   b) Ventilation OTHRI = OTHRI + (reserve block size[4/] x overburden depth in feet[3/] x \$2850)

3 Longwall adjustments

   a) for category 1 (thin) seams·

      o DEVEL = DEVEL x 1 67

      o OTHRI = OTHRI - \$1 1 million

4. Total initial investment (INIT) = OTHRI + DEVEL

5 Working Capital (WORK) = INIT x .075

6 Depreciation (DPCN) = INIT x .07

7. Total Investment (TOTL) = INIT + WORK + DEFRI

8. Taxes and Insurance (TXI) = INIT x .02

TABLE 7-8 (Cont'd)

DEEP MINE MODEL

C Operating Costs

1. Input Data
   - o Union Welfare (WELF), from A.5
   - o Taxes and Insurance (TXI), from B.8
   - o Direct Labor (DRCT)
   - o Cleaning Costs (CLNCOST), from A 4
   - o Operating Supplies (OPSUP)
   - o Power and Water (POW)
   - o Base Mine Production (BASE)
   - o Other (OTHR)
2. Operating supplies adjustment·
   OPSUP = (OPSUP ÷ BASE) x RAW 3/
3. Indirect Costs (INDC) = (OPSUP + DRCT) x 15
4. Total Operating Costs (TOTOP) =
   (DRCT x 1.4) 4/ + OPSUP + INDC + OTHR + POW + CLNCOST + TXI + WELF

D. Revenue Calculation

1. Input Data
   - o Total Investment (TOTL), from B.7
   - o Depreciation (DPCN), from B.6
   - o Operating Costs (TOTOP), from C 4
2. Given the supply region, select:
   - o Severance tax rate (SEVR)
   - o Royalty rate (ROYAL)
3. Calculate cash flow, adjusted for investment tax credit:
   $$\text{CASH} = \text{TOTL} \div \frac{1}{6.533}$$

TABLE 7-8 (Cont'd)

DEEP MINE MODEL

4. Initial Revenue Calculation· the purpose of this calculation is to allow initial computation of gross profit and revenue These figures must be determined in order to establish the value of the federal depletion allowance This will take one of two forms: 10% of revenue or 50% of gross profit, whichever is smaller The selection of the appropriate depletion allowance must be made before the final revenue calculation can be done

   Solve for Revenue (REV):

   .5(REV) - (.5 x SEVR x REV) - (.5 x ROYAL x REV) = CASH + .5(TOTOP) - 5(DPCN)

5. Final Revenue Calculation

   a) Calculate Gross Profit

      GROSS = REV - TOTOP - DPCN - (ROYAL x REV) - (SEVR x REV)

   b) If (1) REV $\geq$ GROSS then solve for REV

      .75 REV - (.75 x ROYAL x REV) - (75 x SEVR x REV) =

      CASH + 75 (TOTOP) - .25 (DPCN)

      Else

      55 REV - (.5 x ROYAL x REV) - (5 x SEVR x REV) =

      CASH + .5 (TOTOP) - .25 (DPCN)

6. Minimum Acceptable Selling Price (MASP) = REV/CLEAN5/

1/ Union Welfare is not calculated outside of the unionized supply regions (1,2,4,5,6).

2/ Number of unionized employees

3/ 0-500 = 250 ft (category 1)
500- 2000 = 1250 ft (category 2)
J2000 = 2000 ft. (category 3)

4/ i.e., 1, 2, 3, 4, or 5

5/ Clean tonnage

7.3 3 Contour Mine Model

The contour mine model was applied to all surface-mineable reserves in Appalachia; i e., supply regions 1 to 4 In contrast to the underground mine model, the contour mine takes a much more abstracted approach. The model used for the JPL project is an adaption from work done by Newphew and Spore of the Oak Ridge National Laboratory (ORNL) in 1974.[6/] Essentially, ORNL analyzed mining costs for 42 hypothetical contour mines operating under various slope, stripping ratio, and reclamation conditions From this analysis, ORNL was able to develop a single equation which related the minimum acceptable selling price (MASP) to variations in geologic conditions and reclamation requirements

Table 7-9 presents the original ORNL model As the table indicates, costs are dependent on three basic factors. 1) the slope of the hillside being mined, 2) the maximum economical stripping ratio for the mine, and 3) the assumed level of reclamation required Note that unlike the underground mine model, no adjustment is made for size; a constant production level of 150,000 tons/year is assumed for all contour mines

The original ORNL model was developed in 1974 To bring it up to date adjustments were needed for the following factors:

- o Inflation since 1974
- o Union welfare costs
- o Productivity
- o Rate of return and haulage cost adjustments
- o Coverage of stripping ratios in the model
- o Level of reclamation

These adjustments are described below

TABLE 7-9

ORIGINAL OAK RIDGE CONTOUR MINE MODEL

Equation.

$$R(S, G, O) = \exp\,(B_0 + B_1S + B_2G + B_3O + B_4GO)$$

Where		Range of Variable
R =	revenue per ton	
S =	stripping ratio at highwall	20.1 to 30 1
G =	grade of reclamation (0,1,2,3)	0, 1, 2, 3
O =	angle of natural slope in degrees(°)	

The coefficients are

B_0 = 1 060

B_1 = 027634

B_2 = - 095415

B_3 = 014325

B_4 = .0114178

Though the authors did not give any statistical measure of the accuracy of fit (R^2) of the equation to their individual calculated costs, they indicated by comments in the text and in a number of graphs comparing predicted results (from the equation) to calculated results that it was reasonably accurate.

SOURCE: ORNL, "Costs of Coal Surface Mining in Appalachia "

7 3.3.1 Cost Increases Since 1974

The 1974 labor and capital costs implicit in the MASP produced by the ORNL model had to be updated to 1979 levels This was done through a multi-step process.

First, inflation rates for labor and mine equipment from 1974 to 1979 were estimated. These individual inflation rates were then weighted by the relative contribution of labor and capital costs to the MASP to produce a composite inflation adjustment factor The composite factor was then applied to the MASP (exclusive of union welfare costs) to escalate it to 1979 dollars. These same costs were held constant for the 1985 model runs.

For 2000 runs, the labor component of the composite factor was increased by 20 percent, reflecting the previously mentioned tendency for labor cost increases to outstrip, by an average of 1 percent per year, capital cost increases A new composite inflation factor was then calculated.

7.3 3.2 Union Welfare

Firms with work forces organized by the UMW contribute to a union welfare and pension fund. The current contribution rate is the same as that for underground mines -- \$2.05/ton and \$0 94/worker-hour This is considerably in excess of the flat \$0.80/ton used in the ORNL study

The first step in correcting the ORNL MASP for 1979 union welfare costs was to extract the \$0 80 per ton welfare cost used in the original study. In the case where contour mine cost calculations were made for Central Appalachia, no further adjustments were made, since this is a predominately non-union area In the remainder of Appalachia \$2 49 was added per ton to reflect current union welfare costs. This figure was derived as follows:

$$\frac{(\$0.94 \times 300 \text{ working days} \times 8 \text{ hours/day} \times 29 \text{ workers})}{150{,}000} + \$2.05 = \$2.49$$

The estimates for working days, hours per day, and number of union workers employed were derived from a detailed contour mine cost example presented in the ORNL report and from a DOE analysis of contour mining costs [7/]

7.3.3.3 Productivity

The mine productivity used in the one detailed cost example presented in the ORNL report was approximately 31 tons per man-day. An examination of current productivity figures for Appalachian contour mining areas indicates that a figure of 19 tons per man-day was more reasonable, or a 60 percent difference. Since the labor-to-machine inputs ratio in contour mining is essentially fixed (for example, one bulldozer to one operator) and can be considered a subunit of productivity, one can assume that overall cost estimates are too low Therefore, all costs (excluding the additional UMW contribution) were adjusted upwards by a factor of 1.6

7.3 2 4 Rate of Return and Haulage

The ORNL model assumed a 12 percent rate of return for a mine In order to convert the costs to the 15 percent rate of return basis used for all coal production costs in the EEA analysis, an adjustment factor was calculated based on the average difference in selling prices of coal at 12 percent and 15 percent returns for individual mines ORNL included a table of selling prices for each mine type, assuming these two alternative rates. The average of the costs calculated at a 15 percent return are 103 percent of the costs calculated at 12 percent Thus a correction factor of 1.03 was used.

An adjustment was also made to account for the relatively low coal haulage cost allowed by ORNL. Its estimate of 27¢ per ton compares to an average cost of coal haulage of $1 65 per ton for eight comparable mines studied by Skelly and Loy Therefore, an increase was made of $1.11 per ton to allow for a more reasonable total of $1.38 per ton

7 3.3 5 Ranges for the Stripping Ratio Variable

In order to adapt the ORNL results to this study, the range of prediction had to be extended to include stripping ratios of 5.1, as compared to their low ratio of 20:1. It was felt that the expected changes in costs which result from modifications of this kind are dependent on gradual or proportional modifications in mine geometry rather than radical shifts in mining method. Therefore, the basic ORNL equation was used for the extrapolation, substituting values outside the range tested by ORNL.

7.3 3 6 Reclamation

The maximum reclamation level for the ORNL Model (level 4) is assumed for all cases This reflects current federal legislation and regulatory requirements

7 3.3.7 Contour Mine Model Outline

Table 7-10 presents the variables and input data for the EEA version of the contour mine model Table 7-11 outlines the model itself, along with a sample calculation.

7.3 4 Area Mine Models

The area mine model used in the JPL study is derived from a mine model developed in 1975 for the Energy Research and Development Administration (ERDA).[8/] The ERDA model is an extremely detailed simulation consisting of 15 "micromodels," each of which simulates a particular surface mining function, such as haulage. For a given level of production and set of geologic conditions, the micromodels allocate the required men, equipment, and operating supplies to complete each mining task The costs from each of the micromodels then feed into a cash flow analysis program which, given such financial parameters as the desired rate of return, calculates the minimum acceptable selling price (MASP) for each ton of coal.

TABLE 7-10

CONTOUR MINE MODEL INPUT DATA

(   ) = Variable Name

- Slope (SLOPE)

  10°

  18°

  25°

- Stripping Ratio (STRIP)

  5:1

  10 1

  20·1

- Inflation Factor (INFLAT)

  1985 = 1.87

  2000 = 1 92

- Union Welfare (WELF)

  $2.49, except in non-union areas (supply regions 3, 7 to 15), where welfare costs equal zero.

TABLE 7-11

CONTOUR MINE MODEL OUTLINE AND EXAMPLE

- 1985 Case
- Steep Slope (25 Degrees)
- Stripping Ratio of 20·1
- Union Mine

- Variables

  WELF = \$2 49   SLOPE = 25

  STRIP = 20

  INFLAT = 1.87

- Base Cost

  BASE = \$12 66/ton = Exp (1 06 + (STRIP x 027634) - .286245 +
  (SLOPE x 014235) +
  (SLOPE x 0232534)

- Final Cost

  (BASE - .8 + 1 38) x (INFLAT x 1 6) + (WELF) x 1.03 = \$43 37/ton

The ERDA model was adopted for use in this study by adjusting the results from six detailed case studies in which the ERDA model was run for different coal basins. The case studies, and the EEA model supply regions to which they were applied, follow.

ERDA Model Case Studies	EEA Supply Regions Applied to
Area Stripping with Draglines	
o Multiple Dipping Seams	12, 13
o Texas Lignite	8
o Illinois Thin Seam	5, 6, 7
o Four Corners	14, 15
o Fort Union Lignite	9
Area Stripping with Shovels and Trucks	10, 11

The ERDA model case study results were adapted to this analysis by 1) taking the case study MASP as a base cost, and 2) adjusting it to reflect the geologic and financial parameters used in the EEA model Specifically, adjustments were made for the following factors

- o Severance tax and royalty rates
- o Coal handling costs
- o Union welfare costs
- o Mine size.

These adjustments are discussed below.

7.3.4.1 Severance Tax and Royalty Rates

The case studies used a flat royalty charge per ton which did not reflect the variance in actual regional rates (see Table 7-2) A factor used to adjust the base for the proper royalty rate was calculated as follows·

[(ERDA Rate - Actual Rate) x 5] + 1 = royalty adjustment factor

(where .5 equals 1 minus the marginal income tax rate)

The ERDA case studies also failed to include any severance taxes (Table 7-2) To account for severance taxes an adjustment factor was calculated for each region as follows

(Regional rate x .5) + 1 = severence tax adjustment factor

7 3 4 1 Return on Investment and Tax Adjustments

The base solution for each case study was calculated for a 12 percent return on investment (ROI) However, sensitivity runs for the case studies presented an alternative solution for the 15 percent return used in the EEA model. This alternative solution could not be used directly, since backup data needed for additional adjustments were presented only for the base solution Instead, a ratio was taken between the base solution and the alternative solution, thereby yielding a factor used to adjust the MASP to reflect a 15 percent return after all the preliminary tax, geologic, and other adjustments are made

A similar method was used to account for tax effects on the MASP In each case study, the base case solution which is to become the final MASP is reduced slightly due to unspecified tax effects As in the case of the ROI adjustment, this final figure could not be used directly, since needed backup information available for the base case solution was not presented for the final tax-adjusted solution. Instead, a ratio of the base and tax-adjusted solutions was calculated and applied along with the ROI correction factor as a final step in the sequence of adjustments

7.7.4.2 Inflation

Inflation was handled here in much the same way as it was for the contour mine model. From information provided in each case study, it was possible

to calculate the proportions of the base MASP attributable to labor and capital. Inflation rates for each were calculated from DOE and Department of Commerce sources and weighted according to their percentage contribution to the MASP This provided a composite inflation factor which was used to escalate costs to 1979 dollars. These costs were assumed to remain constant through 1985. For 2000, a modified composite factor reflecting a 20 percent real increase in labor costs was calculated

7.3.4.3 Coal Handling

All the case studies assumed the maximum level of coal preparation, including washing. This is a pessimistic assumption, since area-mined western coal is generally low in sulfur content and requires minimal preparation, generally just crushing and screening

For each case study, the individual preparation cost components were presented Those components beyond the minimum required handling were subtracted from the base cost

7.3.4.4 Mine Size

The base cost for each of the six area mine models had to be adjusted to reflect the mine sizes used in the EEA model This was done by reference to sensitivity analyses provided for each case study, which presented alternative MASP's for different mine sizes From these alternative solutions, it was possible to calculate adjustment factors for the base costs through the following formula:

$$\text{SIZEFAC} = 1 + \frac{\left| \dfrac{\%\ \Delta,\ M_1,\ M_2}{\%\ \Delta,\ S_1,\ S_2} \quad \times \quad \%\ \Delta,\ S_1,\ S_e \right|}{100}$$

Where: SIZEFAC = the size adjustment factor for a particular EEA model mine size (S_e)

M_1 = base case MASP

M_2 = alternative MASP associated with S_2

S_1 = base case mine size

S_2 = alternative mine size closest to S_e

S_e = an EEA model mine size

7 3.4 5 Overburden Handling

Part of the MASP is the cost of removing the overburden which covers the coal, a cost which will vary with the stripping ratio. Therefore, adjustment factors were needed to modify the base cost to reflect the EEA model stripping ratios (5 1, 10.1, 20 1) As in the case of the mine size adjustments, the stripping ratio adjustments were calculated by making use of sensitivity analyses which provided alternative MASP's for different stripping rations. The first step was to calculate the cost for moving a cubic yard of overburden.

$$C = (M_2 - M_1 + OB_1) - ST_2 - 2$$

Where C = the cost of moving a cubic yard of overburden per ton of coal
M_1 = MASP for the case study mine
M_2 = MASP for the highest striping ratio sensitivity analysis case
OB_1 = the overburden removal cost per ton for the case study mine
ST_2 = the stripping ratio associated with M_2

The quantity above is divided by two because the ERDA costs are calculated in terms of the average stripping ratio, while the EEA model uses the maximum stripping ratio, thereby spreading the removal costs over twice as much overburden.

Since the overburden removal costs per cubic yard and the stripping ratio are directly proportional, the correction factor for a given stripping ratio is calculated as follows:

$$OVERB = (C \times ST_e) - OB_1$$

Where: OVERB = overburden cost correction factor
C = the cost of moving a cubic yard of overburden per ton of coal
ST_e = an EEA model stripping ratio
OB_1 = the overburden removal cost per ton for the base case mine

7.3.4 6 Welfare Costs

All the ERDA case study mines were assumed to be unionized. In reality, outside of the Midwest (supply regions 5 and 6) area mines are rarely unionized Therefore, two adjustments had to be made. First, the union welfare contribution cost portion of the MASP was calculated and extracted This quantity was estimated from information presented for each case study mine on the number of unionized employees, hours worked yearly, and productivity The welfare costs used were those in effect previous to the 1978 UMW contract - $0.82 per ton and $1.54 per hour worked Second, a new union welfare cost based on 1978 contract provisions ($2.05 per ton and $0.94 per hour worked) was calculated This is calculated only for area mines in supply regions 5 and 6, the two portions of the country where area mines are frequently unionized

7.3 4.7 Area Mine Model Data Inputs and Model Outline

Table 7-12a to 7-12f present the data inputs to the area mine models Table 7-13 presents the model itself, along with a sample calculation

7 4 MINE COST RANGES

The final output of the mine cost models is a single mining cost for each coal reserve block In reality, mines of the same size working similar reserves (or even the same coal seams) may have very different mining costs A number of factors account for this cost variation.

- Old mines may have sunk capital costs, and can therefore price their output on the basis of variable costs.
- In some cases operators will not build mines from scratch but will instead reopen an old mine or abandoned working faces in an active mine. This largely eliminates development costs
- Management and labor efficiency may vary for any number of reasons from mine to mine.
- Mines can buy all new equipment, or can purchase some used equipment, thus reducing capital costs

TABLE 7-12a

Area Mine Model Inputs

Mine Type: Illinois Basin Thin Seam (Dragline)

Supply Regions Applied To: 5, 6, 7

ERDA Base MASP: $13.27

Overburden Adjustment (by stripping ratio):

5:1	10:1	20:1
-$5.15	-$4.55	-$3.35

Handling Adjustment: -$1.93

Inflation Factor:

1985	2000
1.29	1.33

Revenue Tax Adjustment: 0.99

Return on Investment Adjustment: 1.29

Severance Tax Adjustment:[1/] (Regional Rate X .5) +1

Royalty Rate Adjustment.[1/] [(Regional Rate -.02) X .5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare[2/] Cost Estimate	Size Adjustment Factor
1	$1 60	$2.29	1 17
2	1.60	2.28	1.15
3	1.59	2.27	1.12
4	1.58	2 26	1.09
5	1 57	2.25	1 02

[1/]Regional Rates from Table 7-2

[2/]Equals zero in Supply regions 3, 7-15

TABLE 7-12b

Area Mine Model Inputs

Mine Type Texas Lignite (Dragline)

Supply Regions Applied To 8

ERDA Base MASP: $6.36

Overburden Adjustment (by stripping ratio)	5 1	10 1	20 1
	-$0 74	$1 76	$4 86

Handling Adjustment -$1.6

Inflation Factor:	1985	2000
	1 3	1 35

Revenue Tax Adjustment· 0 98

Return on Investment Adjustment: 1 28

Severance Tax Adjustment [1/] (Regional Rate X 5) + 1

Royalty Rate Adjustment·[1/] [(Regional Rate -.04) X .5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare[2/] Cost Estimate	Size Adjustment Factor
1	$1.53	$2 20	1 35
2	1.52	2.19	1 32
3	1.51	2 18	1 29
4	1.51	2.18	1.26
5	1 48	2 15	1.04

[1/]Regional Rates from Table 7-2

[2/]Equals zero in Supply regions 3, 7-15

TABLE 7-12c

Area Mine Model Inputs

Mine Type. Four Corners (Dragline)

Supply Regions Applied To. 14, 15

ERDA Base MASP $7 69

Overburden Adjustment (by stripping ratio)

5 1	10·1	20·1
$1.25	$0 85	$3 85

Handling Adjustment: -$1.80

Inflation Factor:

1985	2000
1.3	1 35

Revenue Tax Adjustment 0 98

Return on Investment Adjustment: 1.29

Severance Tax Adjustment:[1/] (Regional Rate X .5) + 1

Royalty Rate Adjustment.[1/] [(Regional Rate - 03) X .5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare[2/] Cost Estimate	Size Adjustment Factor
1	$1.55	$2 23	1 33
2	1.54	2 21	1.3
3	1.54	2.21	1.26
4	1.53	2.20	1.21
5	1 50	2 17	1.0

[1/] Regional Rates from Table 7-2

[2/] Equals zero in Supply regions 3, 7-15

TABLE 7-12d

Area Mine Model Inputs

Mine Type. S Wyoming Dipping Seams (Dragline)

Supply Regions Applied To 12, 13

ERDA Base MASP· $18 90

Overburden Adjustment (by stripping ratio). $\frac{5\ 1}{-\$5\ 20}$ $\frac{10\ 1}{-\$2.30}$ $\frac{20{\cdot}1}{-\$3.50}$

Handling Adjustment· -$3 22

Inflation Factor: $\frac{1985}{1.35}$ $\frac{2000}{1.43}$

Revenue Tax Adjustment 1.0

Return on Investment Adjustment 1.16

Severance Tax Adjustment [1/] (Regional Rate X 05) + 1

Royalty Rate Adjustment [1/] [(Regional Rate -.02) X .5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare[2/] Cost Estimate	Size Adjustment Factor
1	$2 20	$2 29	1.38
2	2.20	2 99	1 35
3	2 13	2.90	1.29
4	2 07	2.84	1.23
5	1 90	2.64	1 0

[1/] Regional Rates from Table 7-2

[2/] Equals zero in Supply regions 3, 7-15

TABLE 7-12e

Area Mine Model Inputs

Mine Type. Powder River (Shovel and Truck)

Supply Regions Applied To· 10, 11

ERDA Base MASP. $7 56

Overburden Adjustment (by stripping ratio): $\frac{5\cdot 1}{0}$ $\frac{10\ 1}{\$3\ 24}$ $\frac{20\ 1}{\$8\ 84}$

Handling Adjustment -$1 75

Inflation Factor: $\frac{1985}{1\ 32}$ $\frac{2000}{1\ 38}$

Revenue Tax Adjustment. .97

Return on Investment Adjustment: 1.22

Severance Tax Adjustment:1/ (Regional Rate X .5) + 1

Royalty Rate Adjustment:1/ [(Regional Rate - 03) X .5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare2/ Cost Estimate	Size Adjustment Factor
1	----	----	----
2	$1 6	$2.28	1 43
3	1 58	2.25	1 36
4	1 56	2 24	1 31
5	1.51	2 19	1 05

1/Regional Rates from Table 7-2

2/Equals zero in Supply regions 3, 7-15

TABLE 7-12f

Area Mine Model Inputs

Mine Type· Fort Union Lignite (Dragline)

Supply Regions Applied To: 9

ERDA Base MASP $6.35

Overburden Adjustment (by stripping ratio)

5 1	10 1	20 1
-$0.68	$1 32	$4 02

Handling Adjustment. -$1.74

Inflation Factor:

1985	2000
1.3	1.35

Revenue Tax Adjustment 0.93

Return on Investment Adjustment. 1 29

Severance Tax Adjustment.[1/] (Regional Rate X .5) + 1

Royalty Rate Adjustment:[1/] [(Regional Rate - 04) X 5] + 1

Block Size	ERDA Welfare Cost Estimate	EEA Welfare[2/] Cost Estimate	Size Adjustment Factor
1	$1.51	$2.18	1.35
2	1.51	2.18	1.32
3	1.50	2 17	1.28
4	1.50	2 16	1 24
5	1.48	2.14	1 04

1/ Regional Rates from Table 7-2

2/ Equals zero in Supply regions 3, 7-15

TABLE 7-13

Area Mine Outline and Example

- Powder River Basin, WY, 1985
- 6 75 million ton/year mine
- Stripping Ratio of 5.1
- Variables

  ERDA Case Study Base Cost (BASE) = $7 56/ton

  Overburden adjustment (OVERB) = 0

  Handling adjustment (HANDL) = $1 75

  Size adjustment (SIZEFAC) = $1.05

  ERDA Welfare cost estimate (WELF1) = $1 60

  EEA Welfare cost estimate (WELF2) = 0

  Tax adjustments to revenue (REVFAC) = .97

  15 percent return on investment adjustment (ROIFAC) = 1 22

  Severance Tax adjustment Factor (SEVT) = 1.01

  Royalty Rate adjustment factor (ROYAL) = 1.055

  Inflator (INFLAT) = 1 32

- Model Outline

  $7.36/ton (MASP) = [(BASE + OVERB - HANDL - WELF1) X (INFLAT X ROYAL X SIZEFAC) + WELF2] X REVFAC X ROIFAC X SEVT

Specifically, the single production cost output for each reserve block was taken as a base cost from which a cost range was built:

- For contour mineable reserve blocks, the base cost was taken as a lower bound. Medium and high production costs, respectively 10 and 20 percent higher than the base, were calculated for the reserve block.

- For underground mineable reserve blocks, the base cost was taken as an upper bound Medium and low production costs, respectively 10 and 20 percent lower then the base, were calculated.

A simple example of the impact of these factors can have is to consider a situation where an old mine and a new mine are working the same seam. If the old mine has fully sunk costs, it can clearly produce its coal at a lower price than the new mine. Similarly, if both mines working the seam were newly opened, but one had bought all new equipment while the other had purchased some used equipment, the latter will have less capital investment to recover and thus a lower production cost

This diversity in production costs is most apparent in the long-developed coal fields of the eastern U S., much less so in the newer western coal mines where EEA has observed costs to be much more uniform To reflect this diversity in the east, adjustments were made to the mine cost model outputs for supply regions 1 to 5.

The choice of a 20 percent range was based on EEA contacts in recent years with a large number of coal companies. The contour mine base costs were used as a lower bound, as they appeared to be biased toward the lower end of the production price range for contour mines The opposite was true of the underground mine model.

Once the cost range was established for a reserve block, one-third of the reserve was assigned the high production cost, one-third to the low, and one-third to the medium cost. This meant that no more than one-third

of a reserve could be produced at, respectively, its high, medium, or low cost. The split by thirds was arbitrary, made in the absence of any data to argue for one division over another.

This technique produced in the model the wide diversity of production costs which are characteristic of the Eastern U S Note again that a range was not used for the Western U.S. (supply regions 6-15), where costs are more uniform between similar sized mines in similar reserve blocks

7 5 NOTES

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8. COAL TRANSPORTATION

8.1 INTRODUCTION

This portion of the report will discuss how coal is transported, how transportation rates are set, and how rates are estimated for 1985 and 2000 for use in the EEA coal model. The discussion centers on rail, water, and pipeline transport, since these are the primary means by which coal is moved from the mine site to the consumer.

8.2 BACKGROUND

8.2.1 How Coal is Shipped

Because coal is low in energy content per unit volume, it is most economically transported by bulk carriers.[1/] The three major bulk transport systems are railroads, water carriers, and slurry pipelines. Trucks are also used extensively in transporting coal, but generally for short distances, such as within a mine site.

8.2.1.1 Rail

By far the predominant means of coal transport is by rail. This reflects rail's relatively low cost, and, more importantly, the flexibility and accessibility of the rail network. Unlike water transport, the rail system is available to virtually all coal producers and consumers, for short as well as long hauls. In 1976, the railroads accounted for 75 percent of all coal transported.[2/] Coal transport is a major portion of rail freight carriers' business, accounting for approximately 25 percent of total tonnage originated by the railroads and about 15 percent of their total gross revenues.[3/]

8 2 1.2 Water Carriers

After railroads, the most important coal transporters are water carriers In 1976 they moved 11.8 percent of all coal shipped [4/] Coal transported by water--whether on the Great Lakes, such inland waterways as the Mississippi River, or along the Gulf Coast--may move along part of its journey by rail or truck. For example, Kansas City, St Louis, and Minneapolis-St. Paul are among the transshipment points along the Mississippi and Missouri rivers where western coal, transported by rail, is loaded onto barges for delivery to Midwestern and Southern markets

Water-borne coal shipments are typically larger than rail shipments An average unit train carries about 10,000 tons, while a single tow of 20 open hopper barges can carry 20,000 to 30,000 tons. Even larger shipments are possible the Detroit Edison Midwest Energy Terminal at Superior, Wisconsin, loads rail-delivered western coal onto 60,000-ton capacity dry-bulk carriers for shipment as far east as Buffalo

The large size of shipments helps make water generally the least expensive means, on a tonnage-mile basis, for transporting coal Another reason is, until recently, the Federal government has not charged carriers for waterway maintenance and improvements. The main disadvantage of water transport is its lack of accessibility to many producers and consumers. Thus, most coal transported over long distances must move all or part of its way by rail.

8.2.1 3 Slurry Pipelines

Slurry pipelines involve grinding coal, mixing it with an equal quantity (by weight) of water, and then pumping the mixture to its destination, where the coal is dewatered prior to use. The only slurry system currently in use is the 273 mile Black Mesa pipeline between Arizona and Nevada Although this pipeline has been a success, plans to expand the slurry system have been marked by controversy. Environmentalists have been

concerned about the significant interbasin transfers of water caused by the slurry systems (up to seven billion gallons/pipeline annually) Railroads have opposed pipeline construction for commercial reasons pipeline transport will often offer lower transport rates due to their relatively minimal use of costly fuel and labor Rail operators fear that, because of this cost advantage, they will lose a significant portion of their badly needed coal business to the pipelines. Accordingly, railroads have supported efforts to block approval by state legislatures of the right of eminent domain for pipeline builders, a right they need to acquire state land for pipeline construction

It currently appears that the companies planning to build slurry pipelines will be able to overcome their opposition and that the currently planned system will be in operation by 1985 (see Section 8 4.2 1 2).

8.2 1.4 Trucks

Trucks serve primarily as collectors and distributors of coal. For example, trucks are the main method of moving coal from strip mines to preparation plants, rail or water loading points, or mine-mouth generating plants In contrast, rail, water, and pipeline carriers account for approximately 85 percent of "line haul" shipments--that is, movements from the mine site to the consumer Thus, while trucks are involved in some portion of nearly three-quarters of all coal movements, the average truckload of 20-25 tons covers less than 100 miles In comparison, the typical line-haul distance for coal shipments by rail is 395 miles, and 268 miles for barges [5/]

8 3 TYPES OF RATES AND HOW THEY ARE SET

8.3 1 Rail Rates

There are many types of commodity rates applying to coal movements by rail. The major rates are described below, in ascending order by cost [6/]

- Single-Car Rate: This is a tonnage-based rate involving the use of a single car, usually carrying 100 tons or less Traditionally, these rates have been set by grouping together nearby mines and/or destinations, and then assigning the same rate per ton for the entire group

- Multiple-Car Rate: Multiple-car rates are based on a sufficient tonnage to require the use of two or more cars. Multiple-car rates differ from trainload rates in that the required tonnage, generally 1500 tons, is less than the amount necessary to make up an entire trainload

- Trainload Rate In this case the rate is based on sufficient tonnage to make up an entire train, usually 5000 tons or more The railroad equipment usually is furnished by the carrier and, unlike a unit-train rate, the movement does not have a predetermined continuous cycle of movements between the shipper and the consumer

- Annual Volume and Conditional Rate: A rate based primarily on the stipulation of the movement of a stated tonnage over a specific time period A shipment can range in size from a single carload to an entire trainload

- Unit-Train Rate This is the most economical rail rate The rate is negotiated between the shipper and carrier for a train acting as a shuttle between one origin and one destination The unit-train has a predetermined schedule for loading, haulage volumes, mine departure, generating plant arrival, unloading, turnaround, and return. This fixed schedule permits the railroad to optimize its operations. The shipper often owns the hopper cars, which further reduces rates.[77]

Rail rate determination is normally left to the carriers with the Interstate Commerce Commission (ICC) having veto power. Carriers must file new rates 30 days before they are to be effective. Unless the rates are suspended by the commission, either on its own volition or on the protests of others, the rates go into effect

The rate set by each of the transportation modes can be a one-sided decision on the part of the carrier or a negotiated price agreed upon by the carrier and the shipper. The rate is primarily determined by the cost of the movement. Factors affecting costs include:

- location and distance from origin to destination
- volume and frequency of the movement
- labor and fuel costs
- turnaround time
- maintenance and administration expenses
- ownership of equipment
- necessary purchase of additional equipment

Competition also is a major consideration when determining a rate. Intermodel competition will tend to decrease a coal freight rate, as well as competition to coal from other energy sources. Thus, coal movements having similar cost characteristics may have a wide disparity in rates due to competitive pressures and the dynamics of the negotiating process

Rail rates can be increased by two methods If a single railroad believes a rate should be increased in nominal terms, a petition is made to the ICC for consideration. When a general increase is deemed necessary by several railroads to cover inflating costs, these railroads put together a proposal based on costs and financial needs. The proposal is then submitted to the ICC for a decision within 45 days. During this time, the public may submit protests to the petition. If the proposal is decided to be justified, a general (or "Ex Parte") rate increase goes into effect.

8.3.2 Barge and Slurry Pipeline Rates

Barge rates for coal are not regulated by the ICC, as are rail rates, and therefore are not required to be published. Thus, it is not necessary for barge rates to be classified into any particular category

Every rate is a matter of negotiation, not classification. Slurry pipeline rates most likely will not be regulated. These rates, like barge rates, will not be categorized but will depend upon the conditions of the contract between the shippers and the carriers.

8 4 MAJOR FACTORS AFFECTING FUTURE COAL FREIGHT RATES

Coal freight rates are impeded by non-market forces such as political and social goals, as well as by the market force of competition Inter-modal and interfuel competition affect rates through the economic influences existing in the energy and transportation industries.

8 4 1 Market Factors Affecting Future Coal Freight Rates

Coal freight rates reflect not only the cost incurred by the carrier to move the coal but also reflect the competitive environment in which the rates are determined. The evolution of the various types of railroad freight rates is a result of competitive pressures faced by the railroad industry over the past 50 years Competitive pricing for multiple-car shipments was approved by the ICC in 1939 in an effort to help the railroads compete with barge movements. Annual volume rates were created to thwart the use of alternative energy sources, such as natural gas, and the use of other forms of energy transport, such as slurry pipelines or high voltage wires Unit-train rates were a result of the railroads' desire to promote western coal use in mid-continent markets The most recent decision by the ICC legalizing contract rates, (i e , rates stipulated in a contract between the carrier and the shipper for time periods as long as 30 years) is a recognition that railroads have been at a competitive disadvantage against pipelines and water carriers, who have been able to use long-term contracts. All these rates have been designed to achieve economies in coal handling, in order to offset to the extent possible the effect of revenue losses from downward adjustments necessitated by competition.[8/]

Although coal is now gaining a competitive advantage over oil and natural gas in some markets, the railroads are faced with a new competitive threat from coal slurry pipelines. This threat may alter the railroad freight rate structure still further The railroad interests argue that if pipelines are allowed to capture the future growth in coal traffic, railroad revenues and profitability will be adversely affected and impair the railroad's ability to attract needed investment capital. This loss of revenue may have the effect of increasing rates for other commodities Pipeline interests argue that pipeline contruction will not result in a crippling loss of coal business to the railroads. Instead, they say that only a modest sharing of the enormous future growth in coal traffic will take place. Pipelines will offer previously absent competition for the railroads, to the ultimate benefit of the consumers [9/]

The primary financial advantage of slurry pipeline transportation, as opposed to unit-train transportation, is that pipelines are relatively inflation proof Seventy percent of a pipeline's total costs are fixed costs. Railroads, subject to uncertainties in the cost of labor, maintenance, and fuel (together constituting 75-80 percent of total railroad costs), must pass on the uncertainty in the form of higher rates to the shippers.

Future rate structure changes may result from further deregulation of the railroads, allowing them to pass cost increases onto the customer more quickly This may have the effect of de-escalating rail rates by removing the risk factor. As a result, rates may be determined by each individual movement, as are unit-train rates, diminishing the importance of rail rate classification

8.4.2 Recent Federal and State Regulations

Government regulation, second only to competitive forces, have had the greatest effect on the coal rate structure. Recent and pending legislation,

primarily by the federal government, have important implications for future rates. Much of this legislation directly pertains to regulation of the railroads.

8.4.2.1 Regulations Affecting Barges and Slurry Pipelines

8.4 2.1 1 Inland Waterways Act of 1978

Rail and truck spokesmen have long maintained that barges using the inland water system receive an unfair advantage since, until the enactment of the Inland Waterways Revenue Act of 1978, no user charge was levied on waterway freight transportation for Federal construction, repair, and maintenance of inland waterways, and provision of navigational aids. Railroads construct, repair, and maintain their rights-of-way and, in many cases, pay property taxes on the land and structures Trucks contribute to the construction, repair, and maintenance of roads through various licenses and taxes, although they do not pay their full share [10/]

The Inland Waterways Revenue Act, enacted October 21, 1978, levies, for the first time, a waterway user charge on commercial freight traffic using the 25,000 mile inland waterway system. The user charge is collected in the form of a fuel tax, and is levied at four cents per gallon beginning October 1, 1980, rising to ten cents per gallon by 1985 [11/] The tax is expected to produce several hundred million dollars in tax revenues each year, although the revenue collected will still be less than the annual federal expenditure on the inland waterways

This fuel tax will most likely affect the barge rates. Barge companies are sensitive to fuel prices, since 25 to 30 percent of total barge operating costs are fuel costs. Perceived cross-elasticities of demand between barges and other transportation modes, and the profit margin of the barge companies, will determine how much of the increase in fuel prices is passed on to the shipper in the form of higher rates If

barge companies are forced to substantially increase their rates, competing rail lines may feel they too can increase their rates without any loss of traffic to the barge companies.

8 4 2 1.2 Coal Slurry Pipeline Legislation

Passage of federal and state legislation is neccessary before new coal slurry pipelines can be built. Competition from these pipelines may affect the future rail and barge freight rate structure The major hurdles faced by the pipeline companies are to obtain water rights in certain states and rights-of-way across land upon which railroads currently operate. However, the success of slurry pipeline legislation in the past year indicates slurry pipelines will be built.[12/] Among the major developments are:

- o passage of a slurry pipeline water bill in Utah
- o the overwhelming defeat of a bill to repeal the water rights of the Energy Transportation System, Inc (ETSI) pipeline from Wyoming to Arkansas
- o approval of a bill to grant water rights to the WYTEX pipeline from Wyoming/Montana to the Texas gulf coast
- o a commitment by the railroads to grant coal-pipeline crossings in Kansas, thereby eliminating the necessity of eminent domain legislation or crossing-permit suits in the state
- o eminent domain power for coal-slurry pipelines has been granted in Texas, Oklahoma, Utah, Colorado, Arkansas, and Louisiana[13/]
- o the success of the ETSI pipeline lawsuit in Kansas, Nebraska, and Wyoming to obtain railroad rights-of-way crossings, in many cases, the railroads did not own the land upon which they operated so the land could be obtained from the original landowners without eminent domain power

8.4 2 2 Regulations Affecting Rail Transportation

8 4.2 2 1 The Railroad Revitalization and Regulatory Reform Act of 1976 (4R Act)

The 4R Act (P.L. 94-210) was the first step toward deregulation and modification of railroad regulatory procedures Under the 4R Act, the ICC was mandated to help economically distressed railroads, either by granting special rail-rate increases, or by sponsoring applications for federal assistance to carry out track/equipment upgrading programs.[14/] Because future investments are considered when determining a fair rate, the future rate structure will reflect costs not already incurred by the carrier

The ICC anticipated that this legislation would promote cooperation between the carrier and the shipper The railroad would get more service while the shipper would receive lower rates through a guarantee of business to the railroad. However, in most cases (primarily dealing with western coal movements) the carriers have used the proceedings to issue higher rates for their system revitalization

8.4 2.2.2 Change of Policy on Railroad Contract Rates--Ex Parte 358-F

In the past, contract rates between carriers and shippers were held to be illegal They were thought to be a destructive competitive practice which would have the effect of damaging existing rate structures and reducing competition Over time, however, the ICC did begin to approve reduced rates on annual-volume shipments. Since these reduced rates were open to any shipper who could take advantage of them, they were not held to be unlawfully discriminatory or destructively competitive. Rather, they helped to reduce shipping costs and promote efficiencies and improvements in service. Based on this experience, and in an effort to make the railroads more competitive with pipelines and water carriers (who could offer contract rates), the ICC reversed itself. Since the

Commission's Ex Parte 358-F decision of November, 1978, contract rates have been available to rail carriers.

Contract rates allow better planning on the part of both shippers and carriers. A shipper is guaranteed a certain rate for the period of the contract while the carrier knows what services that shipper will require This allows the railroad to plan for the most efficient allocation of its equipment and other resources. In particular, with a clearer picture of its future revenues, the carrier may not have to increase rates substantially at the present time in order to be certain of having funds for capital improvements in the future From the shipper's standpoint, he benefits from both lower rates and an assured level of service 13/ Along with the introduction of unit-trains, contract rates are the most significant development in the rail freight structure in recent years

8 4.2.2.3 Railroad Transportation Policy Act of 1979 (S. 1946)

The Railroad Transportation Policy Act is the latest proposal to deregulate the railroad industry By minimizing ICC intervention in the rate-making process, supporters of the Act hope to help the railroads by allowing them to rapidly change rates in response to market pressures The current form of the legislation proposes to do away with Ex Parte increases, while limiting annual rate increases to a certain percentage above variable costs These annual increases would be subject to a multi-year ceiling

Debate on this bill centers around three issues. The ICC, National Coal Association, American Association of Railroads, Congress, and other interested parties all disagree on the annual and long-term rate increase limit, and whether the limit should exist at all. They also disagree on whether or not to do away with Ex Parte increases Another suggested option is to treat coal traffic as an issue separate from the rest of the legislation.

Senate action on the bill is expected in 1980 Any form of the legislation may affect not only the rate structure but the process by which rates are created and increased

8.4.2.3 Impact of Environmental Regulations

Federal environmental legislation, culminating in the Clean Air Act of 1977 (P.L 95-95), imposed regulations designed to maintain and enhance air quality. The attractiveness of western low sulfur coal to utilities seeking to meet the regulations as economically as possible created an entirely new western coal movement network and freight rate structure Because unit-trains are the most cost effective type of rail movement over long distances, the majority of rates composing the western freight rate structure are unit-train rates.

8.5 METHODOLOGY FOR DETERMINING FUTURE RATES

In this section the methodology for estimating future coal transportation rates is presented The section is divided into the following four parts·

- A description of the methodology and a comparison with techniques used in other studies;
- A summary of the assumptions made as to future coal transportation methods and patterns,
- A description of how, given the underlying assumptions, rates were calculated for 1979 cost conditions;
- A discussion of how the calculated rates were escalated (in constant 1979 dollars) to reflect anticipated real cost increases for 1985 and 2000.

8.5.1 Description of the Methodology and Comparison

8.5.1.1 Methods Used in Other Studies

Over the past three years, many groups have attempted to estimate railroad freight rates. Two approaches have been used. The first approach,

developed by General Research Corporation,[16/] uses actual railroad fixed and variable costs to derive a freight rate This approach was inadequate for the purpose of this study These derived rates represented the minimum rate at which the railroads can transport the coal and cover their costs However, these rates do not reflect the competitive environment in which the railroads operate and thereby do not reflect the actual rates faced by the shipper.

The other more common method of rate estimation is regression analysis based on a sample of actual railroad coal freight rates Batelle Memorial Institute,[17/] Charles River Associates,[18/] ICF, Inc.,[19/] and the Department of Energy's Midterm Energy Forecasting System (MEFS) model[20/] all basically follow the same estimating process.[21/] Regression coefficients of average unit-train fixed and variable costs per ton are first derived from a multiple regression of data found in the ICC's Ex Parte 270 "Investigation of Freight Rates-Coal." The data presented in Ex Parte 270 are 1972 rail rates Therefore, the rail rate estimates developed from these regression coefficients represent average 1972 coal transport costs In order to escalate these rates up to 1978 constant dollars, the rates are first increased to 1975 levels using the American Association of Railroads (AAR's) rail cost index An index of GNP growth is then used to express these rates in 1978 constant dollars.

In those studies which estimate barge rates, the same approach is used The barge regression coefficients are based on 1973 barge rates presented in an A. T. Kearney study [22/] Barge rates derived from these coefficients are subsequently escalated to 1978 levels by using various transportation cost and GNP indices.

8.5.1.2 Methodology Used in This Study

The methodology used in this study proceeds in three basic steps:

- o First, underlying assumptions are made about how, in 1985 and 2000, coal is likely to be moved between the supply regions

established for the model (Section 8.5 2) This may involve increased use of a current method, such as unit-trains on current routes or the opening of entirely new rail, barge, or pipeline links between regions for which there are currently no coal movements.

- o Given the future transportation structure, baseline rates for coal movements between the model's supply and demand regions are calculated from 1979 values for similar movements (Section 8 5.3).
- o These 1979-based rates are then escalated or reduced (in constant dollars) to reflect estimated changes in cost conditions through 1985 and 2000 (Section 8 5 4)
- o Between any pair of supply and demand regions there can be as many as four possible transportation methods--rail, rail-barge, barge, and pipeline. In such cases rates are calculated for all cost-competitive options; then the least expensive rate is introduced into the model as the transport cost between those regions.

The central feature of this methodology, and the one which most clearly separates it from that used in other studies, is the reliance on 1979 rate data. It appears that the 1979 rate structure includes all of the elements which will be found in 1985 and 2000, therefore, rates can be estimated for future coal movements by selecting the appropriate rate-type and associated cost from the 1979 rate structure and escalating (or reducing) the cost to reflect future conditions. Using actual 1979 data avoids the potential errors which may occur by escalating old data to 1979 values.

8.5 2 Assumptions Made in Determining Future Freight Rates

Freight rates for all transportation modes will vary depending on the conditions of the movement. In order to ensure consistency when determining freight rates for this study, certain assumptions, reflecting the structure of coal transportation over the next twenty years, must be made.

8 5.2.1 Rail Transportation

Unit-trains are assumed to be the dominant form of rail transportation for coal over the next twenty years By 1978, unit-trains handled 50 percent of all coal hauled by railroads, compared to 40 percent in 1975, and only 27 percent in 1968. The trend toward increasing use of unit-trains is further exemplified by the fact that, between 1972 and 1977, there was a 44 percent increase in coal tonnage moved by unit-trains, while there was only a 9 4 percent increase in total coal tonnage moved via rail.[23/] The inherent efficiencies of a unit-train, through elimination of expensive switch movements, time consuming delays in rail freight yards, and the risk of underutilized equipment, make this form of rail transportation most economical for most coal hauls. Large annual and trainload volumes and rapid turnaround time also enhance the efficiency of a unit-train movement.

For the purpose of this report, the following assumptions about rail movements were made:

- o Unit-train movements of 100, 100-ton capacity open hopper cars
- o Minimum annual volume shipped--1 to 1.5 million tons
- o Relatively rapid loading and unloading
    - 4 to 5 hours to load and unload in the West
    - 10 to 24 hours to load and unload in the East due to older and smaller terminals than in the West

8.5.2.2 Barge Transportation

Barges, like the railroads, achieve greater cost efficiency by hauling large annual volumes and by rapid turnaround time. The characteristics of a barge movement to a large consumer, assumed to exist for all barge movements in this report, are·

- o Minimum annual volume shipped--2 to 4 million tons
- o Relatively rapid loading and unloading--3,500 to 6,000 tons per hour

8.5.2.3 Coal Slurry Pipeline Transportation

The first assumption made about coal slurry pipelines is that they will be built and be operational by 1985. Current trends in coal slurry pipeline legislation, explained in Section 8 4.2 1 2, indicate that slurry pipelines are winning the legal battles which are the major obstacles to construction.

The second assumption pertaining to the pipelines is an annual capacity of 80 million tons per year for the entire system. This figure reflects the estimated annual capacities for the ETSI and the WYTEX pipelines (25 million tons each), and the Appalachia-Florida pipeline (30 million tons). The actual length of each pipeline is assumed to be equal to present construction estimates.

8.5.3 Selection of Baseline Rates

Given the set of assumptions described above, potential means of transporting coal were specified for each pair of supply and demand regions for which coal movement is practical. As noted, as many as four different transportation links are available for each pair of regions

Once the possible transportation links were set, the rates for each option were calculated as follows:

- o Rates for existing rail movements are taken from actual July, 1979, unit-train and volume tariffs filed with the ICC.
- o Rates for existing barge movements are from estimated 1979 barge rates quoted by barge companies involved in coal operations
- o Rates for presently non-existent unit-train and barge movements are estimated from a representative per ton-mile rate for a similar movement. The per ton rates are calculated using the mileage along the shortest or most probable route.
- o Slurry pipeline rates are based on an estimate for the ETSI pipeline system by T. C. Aude, general manager of Pipeline Systems, Inc [24] This estimate is given as a 1979 tariff so no additional adjustment is needed. Rates for the Florida and

Texas Eastern pipelines are adjusted from the ETSI pipeline estimate to reflect variance in pipeline length

8.5.4 Rate Adjusters for 1985 and 2000

Once the baseline rates have been set for each possible transportation link, they must be adjusted to reflect changes in costs and market conditions through 1985 and 2000. The methods used to make these adjustments are described below.

8 5 4 1 General Factors Affecting Real Rates

Real increases or decreases in rates are the result of several pressures Several factors act to increase costs Variable costs which rise faster than the inflation rate may cause real rate increases The need for revenue to finance capital investment in equipment or rights-of-way, or increased maintenance expenses as equipment and rights-of-way age, all put upward pressure on freight rates.

On the other hand, competitive forces put downward pressure on rates Competition between carriers and between transportation modes generally prevents a given carrier from greatly increasing its rates The promotion of the new volume types of movements indicates carriers' efforts to use economies of scale to maintain low, cost competitive prices. Also, overcapacity in some areas enhances competitive pressures and puts a further limit on price increases

8 5 4 2 Railroad Rates

8.5.4 2.1 Western Regions of the United States

Railroad rates in the West are not expected to increase in real terms over the next twenty years. The western rates are primarily for unit-trains and were set primarily within the past three years These new rates already account for the financial demands the carriers will face

through the end of the century, including the capital investment in equipment and rights-of-way needed to handle increasingly large volumes of coal, competitive pressures, the great distances to eastern markets, and maintenance expenses.

Most western rate makers anticipated the need for more capital and created rates to reflect this. The ICC and DOE's Midterm Energy Forecasting System (MEFS) also project constant real western rates through 2000

8.5.4 2 2 Eastern Region of the United States

Eastern region rail rates are anticipated to increase 18 percent in real terms by 1985 and then remain constant to 2000 Eastern railroads will need to renovate their track as well as to buy new equipment to keep up with increased coal demand. However, eastern coal rail rates, most of which were established years before the recent increase in coal demand and the implementation of volume and unit-train movements, do not reflect the need for additional investment capital. MEFS assumes a 15 percent real rate increase by 1985 will generate the revenue needed for additional capital investment. Yet the recent award of a 22 percent real rate increase to the Louisville and Nashville Railroad on coal-related movements makes the MEFS estimate appear too low The general feeling at the ICC is that most eastern railroads will ask for, but not be granted, a real rate increase as high as the one granted the Louisville and Nashville Railroad Other eastern railroads are not expected by the ICC to need as much financial assistance as did the Louisville and Nashville Railroad.

Competition from western and foreign coal and overcapacity in some areas of the east will also prevent real rates from greatly increasing. More widespread implementation of volume and unit-train rates in the East will add to the downward pressure on real rates

After considering the MEFS estimate in the light of ICC rate decisions and the probable competitive environment, 18 percent is assumed to be the real rate increase in the East by 1985. After 1985 eastern rail rates are not likely to increase in real terms, since all major improvements are assumed to be in place by that year MEFS and the ICC both agree on this point

8.5.4 3 <u>Barge Rates</u>

Barge freight rates for coal are assumed to increase 18 percent in real terms by 1985 and then remain constant to 2000 Although the water carriers do not need additional capital to upgrade or build new rights-of-way (the Federal government bears that expense) the barge companies will need to purchase new equipment and to upgrade transshipment points in order to handle the expected increase in coal traffic. Even if the barge companies do not own the transshipment facilities, the cost of any capital investment will most likely be passed on to the shipper in the form of higher transshipment charges.

Water carriers are affected by rising fuel costs as much as or more than the railroads While 15 percent of a railroad's total costs are fuel costs, fuel costs can amount to 30 percent of a barge company's total expenses The Inland Waterway User Tax, to be implemented late in 1980, will also increase fuel costs. This tax, combined with the escalating price of diesel fuel above the inflation rate, will put upward pressure on real barge rates.

Competition plays an important part in determining the size of real rate increases. In the case of any transportation mode, competition prevents rates from skyrocketing. However, if a competing railroad is forced to increase its rates, the barge company most likely will not hesitate to do the same. This situation will likely arise in the East, where most barge lines operate. Barge rates are therefore assumed to increase 18

percent in real terms until 1985 when, as noted above, eastern rail rate increases should level off. After 1985, competition is assumed to keep the real rates from further rising.

8.5.4.4 Slurry Pipeline Rates

Coal slurry pipelines are assumed to be under construction until 1985 so no adjustment from 1979 to 1985 is necessary From 1985 to 2000, the real rates for coal slurry pipelines are assumed to decline. This decline is attributable to the large fixed cost component of slurry pipelines which limits the impact of inflation The increase in nominal rates for railroads, for which variable costs are up to 80 percent of total costs, is assumed to be equal to the rate of inflation between 1985 and 2000. Slurry pipelines have only 30 percent variable costs, so their nominal rates should increase less than the rate of inflation. In effect, slurry pipeline real rates decline relative to rail and barge rates.

There are two factors which could moderate or reverse the projected decline in real pipeline rates. If the cost of debt increases significantly, the tariff may increase to cover the additional cost Also, environmental costs may be added to the economic costs embodied in the rate Any increases in the estimated coal slurry pipeline rates due to these additional costs should not be significant enough to bring the rate up to the level of the competing rail rate.

8.6 ANALYSIS OF RATES

In this section the projected rate structure for 1985 and 2000 is discussed Following a summary of the overall coal movement patterns expected for the future, the individual cost characteristics of rail, barge, barge-rail, and pipeline rates are analyzed. The section concludes with a discussion of the possible degree of variance around the rates chosen for use in the model. Table 8-1 presents the transportation rates used in the model.

Table 8-1

TRANSPORTATION RATES

SUPPLY / DEMAND	1 OH	2 N WV/PA/MD	3 S WV KY/VA/TN	4 AL/S TN	5 N KY/IN/S IL	6 KA/MO/IO/IA	7 OK/IA BITUMINOUS	8 TX/LA/AR LIGNITE	9 ND/MT LIGNITE	10 M	11 WY POWDER RIVER	12 S WY	13 NM CO/N UT	14 S UT/S CO	15 A/NM
NEW ENGLAND/NY 1	19 29	13 32	20 40	25 20	23 84	27 45	30 47			30 25					
MD/NJ/DE 2	12 90	7 51	11 34	19 71	21 63	27 32	30 34			34 00					
PA 3	5 90	3 86	12 15	16 80	12 77	19 08	22 11			31 32					
OH 4	3 78	7 22	8 20	13 26	7 31	15 01	18 04			26 02					
VA/NC 5	16 70	12 47	7 34	7 68	14 36	25 22	23 19								
SC/GA/FL 6	18 40	15 14	11 03	10 53	14 8	20 86	23 32								
AL/MS 7	15 98	19 47	16 01	5 43	11 16	20 08	14 71			30 20	22 38	25 83	24 36		21 7
TX LA 8	20 21	20 38	20 10	12 96	14 16	17 44	0 02	MM		13 93 12 63	13 93 12 53	16 51	5 33		4 8
[illegible]/KY 9	6 41	15 56	15 38	4 38	4 54	10 99	12 41								
[illegible]/MO 10	15 43	19 47	21 64	17 46	9 68	4 75	13 87			13 11	8 95	10 83	10 38		15 42
OK/AR 11	20 58	23 97	23 48	15 78	15 51	5 65	94	MM		17 16	13 01	13 14	12 08		11 [illegible]
WI/MN/IL/MI 12	11 66	14 41	13 65	13 95	6 72	11 71	15 2			15 30	14 20	16 35	16 35		16 0
[illegible]/ND/SD 13									MM	MM	MM	MM			
AZ/CO/UT/NM 14													MM	MM	MM
CA/NV/OR/WA/ID 15										22 69	23 68	11 14	12 78		17 0

See next page for key.

SOURCE   EEA Estimates

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KEY TO TRANSPORATION TABLE

(   ) = no movements permitted

B = barge

S = Great Lakes steamship

MM = minemouth consumption

P = slurry pipeline

All other movements are via unit-train

8.6 1 Future Coal Movement Patterns

8.6.1 1 Summary

8.6.1.1.1 Coal Movement by Barge-Rail

Although eastern coal can be transported to midwestern markets by barge, barge-rail transshipment costs make barge rates more expensive than competing rail rates In the case of western coal moving to southern markets via barge, the same barge-rail transshipment costs make all rail unit-train rates appear more attractive Most waterborne coal will originate in the eastern coal supply regions, destined for southern markets via the Mississippi and Ohio rivers, or will originate in Montana and be transported through the Great Lakes to northeastern markets

8.6.1.1.2 Coal Movement by Pipeline

Coal slurry pipelines will be used predominantly in the West to transport coal from Montana and Wyoming to the Texas/Louisiana area Unit-trains will also compete for these shipments but most likely will not be able to match the comparatively low slurry pipeline rates However, in the East, trains will be the less expensive and preferred means of transporting coal from Appalachia to Florida.

8 6 1 1.3 Coal Movement by Railroads

Almost all coal moved in significant volume will be transported by unit-trains Practically all movements of eastern and southern coal will be by unit-trains to other eastern and southern markets No coal mined east of Illinois, transported by rail or by any other means, will be shipped to markets west of the Mississippi River Unit-trains will compete with slurry pipelines and barges for southern markets Unless consumers are located relatively close to the Great Lakes, practically no western coal will be shipped to northeastern and southeastern demand

regions Western coal, primarily consumed within western and midwestern markets, will be transported almost exclusively by unit-trains

8 6.1.1 4 Minemouth Coal Consumption

All lignite mined in the Texas/Louisiana/Arkansas area and the North Dakota/Montana area, and all coal mined in the southern Utah/Arizona area, will be used for intra-regional consumption. Therefore, the effective transportation cost within these regions is zero considering that the lignite will be consumed at the minemouth This is also the case for that portion of western coal production which is both mined and consumed within the Rocky Mountain regions

8 6.2 All-Rail Routes[25/]

On the basis of transportation costs, coal demand regions are not necessarily limited to the coal supply regions nearest to them Generally, the rail rate per ton-mile decreases as the distance travelled increases. This inverse relationship enables western coal supply regions, up to 1,600 miles away from a particular midwestern or southern coal market, to compete with the eastern coal suppliers. Western rail rates per ton-mile can be 36 percent to 100 percent cheaper than an eastern rate for a similar movement. Faster turnaround time, newer track and equipment, and the predominance of shipper-owned cars in the West also enables the western railroads to offer significantly lower rates per ton-mile than the East. Table 8-2 shows a comparison of eastern and western all-rail rates to the South and the Midwest.

Because the distance and operating conditions under which most western coal suppliers bring coal to the Midwest are approximately the same, unit-train rates are quite similar. Table 8-3 shows how competitive these rates can be.

TABLE 8-2

COMPARISON OF ALL-RAIL ESTIMATED 1985 UNIT-TRAIN RATES

	$/Ton	Mileage (one-way)
To Mobile, AL		
Uniontown, PA	19.47	1,076
Kansas City, MO	20.08	1,110
Starlake, NM	21 73	1,630
To Houston, TX		
Kansas City, MO	17 44	964
Rock Springs, WY	16 51	1,497
To Chicago, IL		
Uniontown, PA	14 41	555
Kansas City, MO	11 71	451
Gillette, WY	14.20	1,137

TABLE 8-3

COMPARISON OF ESTIMATED 1985 UNIT-TRAIN RATES
TO THE MIDWEST FROM WESTERN COAL SUPPLY REGIONS

	$/Ton	Mileage (one-way)
To Tulsa, OK		
Gillette, WY	13.01	1,149
Rock Springs, WY	13 14	1 161
To Des Moines, IA		
Rock Springs, WY	10.83	957
Grand Junction, CO	10 98	970
To Chicago, IL		
Rock Springs, WY	16 35	1,303
Grand Junction, CO	16.35	1,309

In the East, competition appears to exist between the northern and southern coal supply regions for midwestern markets Although the actual mileage may differ, unit-train rail rates in the South are generally lower on a ton-mile basis than in the Northeast. Again, faster turnaround times, newer facilities, and shipper-owned cars give southern rail rates a competitive advantage. This accounts for the identical rail rates to Chicago from Bluefield, West Virginia and Jasper, Alabama. However, rail rates from midwestern origins are more competitive with southern rates Thus, these two supply regions compete on a transportation basis for the same midwestern markets Table 8-4 presents these eastern rates for coal moving to midwestern markets

8.6.3 Barge and Rail-to-Barge Routes

Barge rates are generally lower than rail rates on a cost per ton-mile basis. Combined with unit-train movements from the West to ports such as St Louis, Kansas City, and Metropolis, Illinois, the lower per ton-mile barge rates allow western coal to compete for markets along the Mississippi River and Gulf Coast Eastern coal shippers also take advantage of the inland waterways to ship to the South. The barge companies are at a disadvantage to the railroads because their distribution network is limited to the inland waterways. Often, shippers must rely on the railroads to complete a shipment originated by a barge company. Thus, the additional transshipment fee added to the barge rate diminishes the water carriers' rate advantage.

The Great Lakes are becoming a major coal hauling route to the East and Midwest demand regions. The Burlington Northern Railroad brings coal from Montana via unit-train to the Superior, Wisconsin Midwest Energy Terminal for transshipment onto large dry bulk carriers These carriers deliver coal as far east as Buffalo, New York. In the event a coal consumer is located in Buffalo rather than in Albany (the centroid for demand region 1), the estimated 1985 freight rate may decrease from

TABLE 8-4

COMPARISON OF ESTIMATED 1985 UNIT-TRAIN RATES
TO THE MIDWEST FOR THE NORTHERN AND SOUTHERN COAL SUPPLY REGIONS

	$/Ton	Mileage (one-way)
To Chicago, IL		
Bluefield, WV	13 65	526
Jasper, AL	13.95	654
To Tulsa, OK		
Jasper, AL	15.78	740
Harrisburg, IL	15 51	727

$30 25/ton to a rate quite competitive with coal from Ohio or West Virginia. The savings in transshipment fees and additional rail haulage in New York could make such a decrease possible, thus enabling western coal to penetrate eastern markets.

8.6.4 Coal Slurry Pipeline Routes

A coal slurry pipeline does not necessarily have lower freight rates than unit-trains. Many factors influence the relative costs of unit-trains and slurry pipelines for coal transportation Among these factors are:[26/]

- o Annual volume of coal
- o Distance to be traversed
- o Expected rate of inflation
- o Presence of large customers to receive coal
- o Relative costs of diesel fuel and electricity
- o Railroad track circuity and need for repair
- o Size and spacing of mines
- o Real interest rate
- o Length and speed of trains

Slurry pipelines will tend to be the less costly coal carrier relative to rail if the first six factors are maximimized and the last three factors are minimized. As the annual volume, distance, inflation rate, etc., decrease, and the spacing of mines, real interest rate, and train lengths increase, unit-trains become relatively more cost advantageous for shippers.

In the case of moving coal from Bluefield, West Virginia to Savannah, Georgia, unit-trains have the competitive advantage. The estimated real

1985 slurry pipeline rate is $15 64 while the rail rate between the same two regions is $11.03. Western coal slurry pipelines do not face this same disadvantage vis-a-vis unit-trains. In the case of the WYTEX pipeline, the estimated real 1985 slurry pipeline rate from Miles City, Montana and Gillette, Wyoming to Houston, Texas is $13 93 per ton An identical shipment via rail is estimated to cost $21.96 and $17 91, respectively

8 6 5 Variance in Rates within a Demand Region[27/]

The coal freight rates derived for this study are representative of the rates which are assumed to exist in 1985 and 2000 between each demand and supply region However, an analysis of present carload coal freight rates shows these rates can vary up to forty percent within a single demand region from the same point of origin Depending on the conditions of the movement, volume or unit-train rates from the same origin can vary up to 25 percent to various destinations in one state of a particular demand region. Therefore, the rates determined for this study do not represent a regional rate covering a vast amount of territory These rates represent the most likely estimates of transportation costs from the center of a supply region to the demand center, not geographical center, of a particular region

8.7 NOTES

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25. Rates used in this analysis are compiled by the Mobil Oil Corporation Traffic Department This publication lists all unit train and annual volume coal rates for eastern and western coal as of July 15, 1979.

26. Office of Technology Assessment, A Technology Assessment of Coal Slurry Pipelines (Washington, D.C · U S. Government Printing Office, March 1978) p. 55

27. Carload rates used in this comparison can be found in ICC tariffs.

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9 MODEL RESULTS

In this section, the model results for 1985 and 2000 are presented. The results include production totals by region, differentiated by mining method and sulfur content. The marginal production prices are also presented by sulfur content and supply region. Following a brief overview, the results are discussed in detail for each supply region. Reference should be made throughout this section to Table 9-1, which contains the overall production forecast, Tables 9-2 and 9-3, which contain the price estimates for 1985 and 2000, and Tables 9-4 and 9-5, which provide summary descriptions of mining conditions for 1985 and 2000. Note that limits on the analysis are discussed in Section 4 3

9.1 MODEL RESULTS OVERVIEW

The model's exogenously determined demand level translates into an enormous increase in coal production from current levels. In 1976* total production was 680 million tons By 1985 production is estimated to reach 1 092 billion tons, a 60.6 percent increase. The 2000 production estimate is for 2 145 billion tons, an increase over the 1985 and 1976 levels by, respectively, 96.4 and 215.4 percent.

The areas showing greatest growth after 1976 are generally those supply regions with large reserves of compliance or low sulfur coal These include central and southern Appalachia in the East, and the Power River Basin, Uinta and San Juan reserves in the West. These demand

* 1976 is used as the year of comparison because it is the latest year for which detailed production figures are available The 1976 production figures for western supply regions are estimates, because insufficient information was available on the county level to break state production precisely among the model regions.

TABLE 9-1

COAL PRODUCTION
(millions of tons)

			DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
1.	Ohio	1976	17	30	47	-	-	-
		1985	15	26	41	0	6	35
		2000	31	21	52	-	12	39
2.	N. Appalachia	1976	88	55	143	-	-	-
		1985	58	27	85	-	36	49
		2000	141	20	162	-	105	57
3	C. Appalachia	1976	113	77	190	-	-	-
		1985	128	119	247	128	93	26
		2000	256	144	400	174	180	46
4.	S. Appalachia	1976	10	16	26	-	-	-
		1985	20	43	64	11	38	15
		2000	42	53	95	13	60	22
5.	Illinois Basin	1976	55	81	136	-	-	-
		1985	4	103	107	-	20	87
		2000	59	108	167	-	79	88
6.	Central Midwest	1976	0	18	18	-	-	-
		1985	0	91	91	-	-	91
		2000	0	113	113	-	-	113
7.	Oklahoma	1976	0	4	4	-	-	-
		1985	0	27	27	0	18	9
		2000	0	29	29	-	18	11

		DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
8. Texas Lignite	1976	0	14	14	-	0	0
	1985	0	62	62	-	-	62
	2000	0	229	229	-	-	229
9. MT/ND Lignite	1976	0	21	21	-	-	-
	1985	0	47	47	-	33	15
	2000	0	103	103	-	62	41
10. Powder River Basin - Montana	1976	0	19	19	-	-	-
	1985	0	318	138	120	18	-
	2000	0	178	178	169	9	-
12 S. Wyoming	1976	1	12	13	-	-	-
	1985	0	0	0	0	0	0
	2000	0	0	0	0	0	0
13. Uinta	1976	10	14	24	-	-	-
	1985	63	2	66	55	11	-
	2000	215	29	244	110	134	-
14. 4 Corners	1976	0	5	5	-	-	-
	1985	0	34	34	7	27	-
	2000	-	34	34	7	27	-
15. San Juan	1976	1	5	6	-	-	-
	1985	0	35	35	34	1	-
	2000	0	94	94	66	28	-
Appalachia (regions 1-4)	1976	229	178	406	-	-	-
	1985	221	215	436	139	173	125
	2000	470	238	708	187	357	164

		DEEP	SURFACE	TOTAL	COMPLIANCE	LOW	HIGH
Midwest	1976	55	103	158	-	-	-
(regions 5,6,7)	1985	4	221	225	-	38	187
	2000	59	250	310	-	98	212
Powder River	1976	-	33	33	-	-	-
(regions 10,11)	1985	0	188	188	170	18	-
	2000	0	424	424	269	156	-
Lignite	1976	0	35	35	-	-	-
(regions 8,9)	1985	0	109	109	-	33	77
	2000	0	332	332	-	62	270
Other West	1976	12	36	48	-	-	-
(regions 12 -	1985	63	71	134	96	39	0
15)	2000	215	157	372	183	189	0
TOTAL USA	1976	295	385	680			
	1985	288	804	1,092	405	301	389
	2000	744	1,401	2,145	639	862	646

Note: Numbers may not add due to rounding

Source: EEA estimates.

C-3

TABLE 9-2

Coal Prices in 1985
(constant 1979 dollars)

Supply Region	Sulfur Content	Last Mine to Open: Cost Range	Last Mine to Open: Mine Type	Last Mine to Open: $/ton	Next Mine to Open: Cost Range	Next Mine to Open: Mine type	Next Mine to Open: $/ton
1	H	L	C 11131	23.20	Same as last mine to open		
1	L	H	R 21112	28.95	M	R 21322	30.30
2	H	M	R 21111	26.21	Same as last mine to open		
2	L	L	R 21221	28.80	Same as last mine to open		
3	H	H	R 21121	27 81	M	R 11211	28 95
3	L	H	R 21121	27 81	M	R 11211	28 59
3	C	L	C 22131	29.59	L	C 13121	31 40
4	H	L	R 11211	27.40	L	R 11221	27 40
4	L	L	R 11211	27.40	Same as last mine to open		
4	C	H	R 21122	33.46	M	C 12131	34 03
5	H	L	A 21122	21 08	L	A 11133	22.29
5	L	L	R 21311	24 68	Same as last mine to open		
6	H	B	A 11122	16 21	Same as last mine to open		
7	H	B	A 11232	18 56	B	A 11131	18 90
7	L	B	A 21231	18.90	B	R 21111	34 63
8	H	B	A 21123	11 07	Same as last mine to open		
9	H	B	A 21113	5 41	B	A 31113	5 41
9	L	B	A 21113	5 41	Same as last mine to open		

TABLE 9-2 (Continued)

Coal Prices in 1985

Supply Region	Sulfur Content	Last Mine to Open: Cost Range	Mine Type	$/ton	Next Mine to Open: Cost Range	Mine Type	$/ton
10	C	B	A 21122	8.38	B	A 21113	8 42
10	L				B	A 21112	8 38
11	C	B	A 31133	7.39	Same as last mine to open		
11	L	B	A 21122	7.36	Same as last mine to open		
12	C	B	None		B	A 31123	24 34
12	L	B	None		B	A 21123	24 34
13	C	B	A 21123	24 33	Same as last mine to open		
13	L	B	L 31331	24 15	Same as last mine to open		
14	C	B	A 31121	12 10	B	A 21132	18 68
14	L	B	A 31122	11 84	B	A 11132	18 68
15	C	B	A 31123	15 14	B	A 11122	15 62
15	L	B	A 31123	15 14	Same as last mine to open		

TABLE 9-3

Coal Prices in 2000
(constant 1979 dollars)

		Last Mine to Open			Next Mine to Open		
Supply Region	Sulfur Content	Cost Range	Mine Type	$/ton	Cost Range	Mine Type	$/ton
1	H	H	C 11121	22.90	Same as last mine to open		
1	L	L	C 22131	32 93	H	R 21222	34 23
2	H	L	C 22121	26 05	Same as last mine to open		
2	L	H	R 11221	33 38	H	R 21211	33 85
3	H	L	R 21211	31 29	Same as last mine to open		
3	L	L	C 23121	32 24	M	C 12131	33 40
3	C	L	C 23121	32.24	M	C 12131	33 40
4	H	H	C 22121	30 08	H	R 11211	30.91
4	L	H	R 11211	30.91	L	C 12131	31 72
4	C	H	C 12131	38.06	Same as last mine to open		
5	H	L	A 21122	21 60	L	R 21311	22 53
5	L	H	A 21122	25 92	M	A 11131	26.07
6	H	B	A 21122	16 61	B	A 11132	17 95
7	H	B	A 21231	19 47	B	R 21111	31 43
7	L	B	A 21231	19 47	B	R 21111	31 43
8	H	B	A 11121	11 98	B	A 21133	18 61
9	H	B	A 31113	5 62	B	A 11112	5 77
9	L	B	A 21113	5 62	Same as last mine to open		

TABLE 9-3 (Continued)

Coal Prices in 2000

		Last Mine to Open			Next Mine to Open		
Supply Region	Sulfur Content	Cost Range	Mine Type	$/ton	Cost Range	Mine Type	$/ton
10	C	B	A 31123	8 81	B	R 31311	43 11
10	L	B	A 31123	8 81	Same as last mine to open		
11	C	B	A 31113	7 73	Same as last mine to open		
11	L	B	A 21112	7 70	Same as last mine to open		
12	C		None		B	A 31123	25 78
12	L		None		B	A 21123	25.78
13	C	B	L 21331	25 85	B	A 11122	26.80
13	L	B	L 21331	25.85	Same as last mine to open		
14	C	B	A 31121	12 54	B	A 21132	19 38
14	L	B	A 31122	12 30	B	A 11132	19 38
15	C	B	A 21122	16 22	Same as last mine to open		
15	L	B	A 31123	15.74	Same as last mine to open		

KEY TO TABLES 9-2 AND 9-3

Sulfur Content

H = high (>2 0 lbs. SO_2/mmbtu)

L = low (>1 2 to 2 0 lbs. SO_2/mmbtu)

C = compliance (1.2 lbs SO_2/mmbtu or less)

Cost Range (see Section 7.6)

H = High

L = Low

M = Medium

Last Mine to Open. The last mine type projected by the model to open in a supply region for each supply content. Equivalent to the marginal mine

Next Mine to Open: The source of production if demand were to increase by one unit.

Mine Type Code

Surface Mines.

- o C = contour mines
- o A = area mines

- o numeric code (for values see below)
  - first digit = seam thickness
  - second digit = pitch
  - third digit = slope
  - fourth digit = stripping ratio
  - fifth digit = block size

Deep Mines.

- o R = Room and Pillar
- o L = Longwall

- o numeric code (for values see below)
  - first digit = seam thickness
  - second digit = pitch
  - third digit = block size
  - fourth digit = overburden depth
  - fifth digit = drift or shaft

Values for Mine Codes

o Seam Thickness (1) = 28 to 41 inches
(2) = 42 to 119 inches
(3) = > 119 inches

o Pitch: (1) = 0 to 10^{o}
(2) = 11^{o} to 30^{o}
(3) = >J 30^{o}

o Slope (1) = 0 to 10^{o}
(2) = 11^{o} to 20^{o}
(3) = > 20^{o} to 30^{o}

o Stripping Ratio. (1) = 5 1
(2) = 10 1
(3) = 20.1

o Overburden Depth: (1) = 0 to 500 Feet
(2) = > 500 to 2000 feet
(3) = > 2000 feet

o Drift or Shaft: (1) = Drift
(2) = Shaft

o Block Size: (1) = 6 mmt (million tons)
(2) = 20 mmt
(3) = 40 mmt
(4) = 60 mmt
(5) = 150 mmt

TABLE 9-4

Mining Conditions, 1985
(Percent of Total Production)

Supply Region	Underground Mines: Thick Seams	Underground Mines: Thin Seams	Area Mines: Low Stripping Ratio	Area Mines: High Stripping Ratio	Contour Mines: Gentle Slopes	Contour Mines: Steep Slopes
1	98 %	2 %	* %	* %	97 %	3 %
2	76	24	*	*	20	80
3	33	67	*	*	0	100
4	79	21	*	*	55	45
5	100	0	0	100	*	*
6	*	*	0	100	*	*
7	*	*	0	100	*	*
8	*	*	0	100	*	*
9	*	*	100	0	*	*
10	*	*	100	100	*	*
11	*	*	100	100	*	*
12	*	*	*	*	*	*
13	100	0	0	100	*	*
14	*	*	0	100	*	*
15	*	*	0	100	*	*

NOTE: Thick Seams = over 41 inches
Thin Seams = 28 to 41 inches
Low Stripping Ratio = 5 1
High Stripping Ratio = 10 1, 20 1
Gentle Slopes = 0 to 10°
Steep Slopes = over 10°
* = Not applicable, no mine of that type in the region

TABLE 9-5

Mining Conditions, 2000
(Percent of Total Production)

Supply Region	Underground Mines: Thick Seams	Underground Mines: Thin Seams	Area Mines: Low Stripping Ratio	Area Mines: High Stripping Ratio	Contour Mines: Gentle Slopes	Contour Mines: Steep Slopes
1	95 %	5 %	* %	* %	92 %	8 %
2	67	33	*	*	23	77
3	31	69	*	*	0	100
4	68	32	*	*	45	55
5	100	0	0	100	*	*
6	*	*	0	100	*	*
7	*	*	0	100	*	*
8	*	*	0	100	*	*
9	*	*	100	0	*	*
10	*	*	100	0	*	*
11	*	*	100	0	*	*
12	*	*	*	*	*	*
13	100	0	0	100	*	*
14	*	*	0	100	*	*
15	*	*	0	100	*	*

NOTE: Thick Seams = over 41 inches
Thin Seams = 28 to 41 inches
Low Stripping Ratio = 5:1
High Stripping Ratio = 10:1, 20:1
Gentle Slopes = 0 to 10°
Steep Slopes = over 10°
* = Not applicable, no mine of that type in the region

patterns are a direct result of federal and state air pollution regulations, which require or have the effect of encouraging the use of low sulfur coals (see Section 4). Regions which fill demand in the rapidly growing Sun Belt, such as the Texas lignite fields, also show strong growth.

Marginal production prices are not dramatically higher than current levels in either 1985 or 2000. This is a reflection of the generally large size of the reserve base, and, in particular, of the large reserves of inexpensive to mine low sulfur coal available in the West. For example, although production of Powder River (Montana) compliance coal increases by 100 percent between 1983 and 2000, the marginal production price increases by only $1.45. Even in central Appalachia, a 100 percent increase in production of low sulfur coal causes a relatively modest price increase, from $27.81 in 1985 to $32.24 in 2000

9 2 APPALACHIA (Supply Regions 1 to 4)

9.2 1 Production Patterns

Production patterns in Appalachia clearly reflect the trends in demand favoring low sulfur and compliance coal. Between 1976 and 1985 overall Appalachian production increases only slightly, from 406 mmt (million tons) to 436 mmt, or 7.4 percent. This is because total production in northern Appalachia and Ohio, predominantly high sulfur coal areas, actually declines 64 mmt during this period. In contrast, production increases by 95 mmt in central and southern Appalachia, both of which have significant compliance and low sulfur coal reserves However, the decline in northern production is so large that the net gain is only about 31 mmt.

By 2000, all of the Appalachian regions show production gains. Overall, the increase is from 436 mmt to 708 mmt, or 62.4 percent. The largest

increase is in central and southern Appalachia The combined production gain for these two regions is 184 mmt, compared to 88 mmt for the two northern regions. Note that even in Ohio and northern Appalachia almost all of the gain in production between 1985 and 2000 is in low sulfur rather than high sulfur coal

The large production increases in central and southern Appalachia reflect the locations of these regions as well as the nature of their reserves Central Appalachia, as its name implies, is centrally located and has short transportation links to mid-Atlantic and northern markets Southern Appalachia is well placed to fill demand in the booming eastern portion of the Sun Belt.

9.2 2 Coal Price

For the most part, Appalachian marginal prices do not increase greatly For example, in 2000 Ohio high sulfur coal is projected to cost $22.90, or about the same as today's price Central Appalachian low-sulfur and compliance coal are both priced at $32.24 a ton in 2000, about $5 more than in 1979 The major price increase is for southern Appalachian compliance coal, which reaches $38.06 per ton in 2000, compared to $33.46 in 1985 This large jump, which occurs although production increases only 2 mmt, reflects the relatively small size of the compliance coal reserves in this area (see Section 6 6).

One factor not considered by the model which could cause significant price increases is depletion (i e., reserve blocks being completely mined out of their recoverable coal). This is considered to be a potential problem only for central Appalachian compliance and low sulfur coal reserves, where significant short-term depletion has been considered a possibility. EEA's analysis of the reserve base indicates that at the projected rate of production, depletion should not be a problem through 2000. However, even if there were a significant amount of depletion by

2000, the price impact would probably not be dramatic For example, consider a case in which 100 mmt of central Appalachian production, divided evenly between compliance and lower sulfur coal production, is lost to depletion by 2000. If sufficient mines to replace all 100 million tons of production are opened, the marginal price of compliance and low sulfur coal will both go up moderately, from $32 24 to $36 45 (13 percent) However, note that further production increments will rapidly push the price close to $40/ton

The split between mining methods changes somewhat between 1976 and 1985, from 54 percent underground to 51 percent. By 2000, deep mining is clearly the predominant method, with 66 percent of total production

9.2 3 Mining Conditions

In 1976, 56 4 percent of Appalachian production was deep-mined By 2000 this percentage is projected to rise to 66 4 percent This result is not unexpected, given that about 82 percent of the recoverable Appalachian coal is in underground mineable reserves (see Table 6-3).

Tables 9-4 and 9-5 shows that between 1985 and 2000 there is little change in the distribution of deep mining between thick and thin seam reserves There is a slight increase in thin seam mining in all the regions, a result of production pushing from the best into less favorable reserves Similarly, the percentage of contour mining in steep slopes also increases slightly But as the moderate marginal price increases show, marginal production, except in southern Appalachia, is still taking place in relatively low-cost reserves.

9 3 MIDWEST (SUPPLY REGIONS 5, 6, AND 7)

9.3.1 Production Patterns

Along with the lignite fields to be discussed below, the Midwest is one of the major exceptions to the demand trend favoring production of low

sulfur coals. In 1985 187 mmt or 83 1 percent of Midwestern producation falls into the high sulfur category, representing almost half of total U.S high sulfur production. This coal is used internally and shipped to nearby markets in the border states and on the Great Lakes (demand regions 9, 10, and 12).

By 2000, the production picture changes somewhat Although the region continues to produce large quantities of high sulfur coal, the increase from 1985 is only 25 mmt. In contrast, low sulfur coal production increases by 60 mmt This is largely the result of demand from new powerplants which can most economically meet the NSPS-II standard by dry-scrubbing low sulfur coal, although there is also some wet scrubbing of high sulfur coal by consumers of Midwestern production

9.3.2 Coal Price

The marginal prices in 1985 approximate current levels and change little through 2000. For example, in 1985 the marginal price of Illinois Basin (supply region 5) high sulfur coal is $21 08; in 2000 it is only $0.52 higher. Even in the case of Illinois low sulfur coal, production of which quadruples between 1985 and 2000, the price increase is only from $1.24.

In the central Midwestern states (supply region 6), which has only high sulfur reserves, marginal prices show a similarly modest rise, from $16.21/ton in 1985 to $16.61 in 2000. In Oklahoma (supply region 7), prices also increase only slightly, but this is due to production reaching an economic ceiling. In 1985, the marginal price of Oklahoma low sulfur coal is $18.90, but the price for the next increment is $34.63 As a result, there is no increase in Oklahoma low sulfur coal production between 1985 and 2000. Similarly, production of Oklahoma high sulfur coal rises by only a modest 2 mmt between 1985 and 2000 because additional production would push the marginal price from $19 47 to $31.43.

9 3 3 Mining Conditions

In both 1985 and 2000 most Midwestern coal is area mined, respectively 98 2 and 80.6. However, the estimates for 1985 probably overstates surface mine production This is because the model is projecting a decline in underground mining in the Illinois basin, from 55 mmt in 1976 to 4 mmt in 1985. (The Illinois Basin is the only Midwestern supply region projected to have deep mines.) While some reduction in underground mining is possible, the sharp decline projected by the model is unlikely and probably is a result of the model overstating the economic advantage in this area of surface mining over underground mining The Illinois Basin forecast for 2000 is a more likely situation, with deep mining at about its 1976 level and most of the production growth in surface mining

All of the surface mineable reserves in the Midwest fall into the high stripping ratio categories (10 1 and 20 1), reflecting the thin seam thicknesses typical of the surface reserves in this area. All underground production in both 1985 and 2000 is projected to take place in the thicker seam thickness categories (>41 inches)

9.4 POWDER RIVER BASIN (Supply Regions 10 and 11)

9.4 1 Production Patterns

The Powder River basin contains very large reserves of low sulfur and compliance coal which can be inexpensively surface mined Not surprisingly then, this region shows rapid production growth from 33 mmt in 1976 to 188 mmt in 1985 and 424 mmt in 2000 In 1985, 90.4 percent of the production is of compliance coal, primarily for power plants falling under the old NSPS By 2000 about 36.8 percent of production is in low sulfur coal, reflecting increased demand from utilities dry-scrubbing under NSPS-II and from new industrial boilers. The Powder River coal is widely shipped, filling demand throughout the Great Plains, Southwest, Midwest, and Rocky Mountain States (demand regions 8, 9, 10, 11, 12, and 13).

9.4.2 Coal Price

Powder River Basin coal currently sells for as low as \$6 00/ton, an undervalued cost caused by overcapacity in the area. By 1985 the marginal price in the Wyoming portion of the Basin (supply region 11) is projected at \$7.39/ton for compliance coal and \$7 36 for low sulfur coal By 2000, the marginal prices increase only \$0 34/ton This increase is entirely due to labor inflation, since marginal production in 2000 is from the same reserves as in 1985

In the Montana portion of the Basin (supply region 10) marginal prices also change little between 1985 and 2000. However, by 2000 all the low-cost reserves of compliance coal are in full production, the next increment of production would push the marginal price from \$8 81/ton to \$43 11. This effectively puts a limit on compliance coal production from this region

9.4 3 Mining Conditions

All coal in the Basin is surface mined from low stripping ratio reserves (5:1 or better)

9 5 LIGNITE FIELDS (SUPPLY REGIONS 8 AND 9)

9 5 1 Production Patterns

Along with the midwestern reserves, the lignite fields of Texas and the northern Great Plains are the only primarily high-sulfur coal reserve areas for which the model forecasts major growth. In Texas, production is projected to increase by 1535.7 percent between 1976 and 2000, or from 14 mmt of production in 1976 to 229 mmt in 2000. Since lignite cannot be safely transported long distances, all production from this region is used internally (demand region 8). The extremely large growth in Texas production is, in particular, a result of demand from new mine-mouth power plants coming on line to serve a rapidly expanding population

and economy. Most of these are NSPS-II plants which wet scrub the high-sulfur lignite.

The northern Great Plains lignite reserves fall primarily into the low-sulfur coal category. The growth in production in this area is not as large as in Texas but is still considerable, increasing from 21 mmt in 1976 to 103 mmt by 2000. As in the Texas case, the production is largely used for minemouth generation

9.5.2 Coal Price

Although production increases greatly, the forecasted marginal production prices do not change significantly between 1985 and 2000. Great Plains lignite increases by only $0.21/ton from the 1985 price of $5 41, all of which is caused by labor inflation (These low production prices are a reflection of the near ideal mining conditions found in the Great Plains lignite fields--very thick seams located under little overburden) Texas lignite prices show a similarly small change, from $11 07/ton in 1985 to $11 98 by 2000 However, the price for the next increment of production in 2000 would be $18.61. This signals that the lowest cost reserves are all in full production.

9.5 3 Mining Conditions

All lignite is area mined As noted above, the Great Plains reserves present nearly ideal mining conditions; all of the forecasted production takes place in low stripping ratio reserves. In Texas, however, 100 percent of the production is projected to take place in high stripping ratio reserves This helps to explain why the Texas lignite costs about twice as much per ton as the Great Plains lignite.

9 6 OTHER WESTERN REGIONS (SUPPLY REGIONS 12, 13, 14, 15)

9 6 1 Production Patterns

The largest additional portion of production forecasted by the model comes from the Uinta Basin of Colorado and Utah (supply region 13) Production from this region grows from 24 mmt in 1976 to 66 mmt by 1985, and then to 244 mmt in 2000. All of the production is of low-sulfur and compliance coal, mostly for shipment to NSPS-II plants on the West Coast (demand region 15).

The San Juan and Four Corners regions (respectively, supply regions 15 and 14) both produce moderate amounts of low-sulfur and compliance coal San Juan production grows from 6 mmt in 1976 to 94 mmt by 2000. Four Corners production increases from 5 mmt to 34 mmt between 1976 and 1985 But at that point all of the low-cost Four Corners reserves are in full production, and as a result there is no further growth through 2000 (see the price discussion below) Because of limits on the transportation net serving these regions, all the coal is used locally (demand region 14).

For the remaining western region, the southern Wyoming bituminous coal reserves (supply region 12), the model predicts no production at all This is an unlikely occurrence, since in 1976 production in the region was about 13 mmt and is currently up to 20 mmt. The reason for the anomalous results lies with the problems some Midwestern utilities had in the 1970's when they had to shift from high- to low-sulfur coals in order to meet air pollution standards. The logical source for low-sulfur coal would have been the Powder River Basin, except that the coal from this region is subbituminous and thus has a low heat content (8000 to 9000 Btu/lb.). Therefore, to use this coal the utilities would have had to derate their boilers. A more economical alternative for the utilities was to find a nearby source of low-sulfur bituminous coals. The southern

Wyoming mines opened to help meet this demand. However, since the model does not incorporate the problems with capacity requirements that derating would cause utilities, it does not respond as the market did in this special case.

9.6.2 Coal Price

Uinta Basin coal is relatively expensive to mine, with a marginal price of $24.33/ton in 1985 and $25.85 in 2000. What makes it competitive with the much less expensive Powder River coal are transportation factors There is no direct rail link from the Powder River Basin to the West Coast (demand region 15) As a result, transportation costs between the two regions are prohibitively high (about $23/ton) However, there is a direct rail connection from the Uinta Basin to the West Coast, at a cost of only $12.78/ton. This is enough of a cost advantage to give Uinta Basin coal all of the West Coast market

In the San Juan region the production prices increase only slightly between 1985 and 2000, from $15 14/ton to $15.74 for low-sulfur and $16 22 for compliance coal As noted above, all low-cost Four Corners reserves are in full production by 1985 at a marginal price of about $12/ton Since the next increment would cost $18.68/ton, there is no additional production through 2000

9 6.3 Mining Conditions

The Uinta Basin is the only area west of the Mississippi where the model forecasts underground mining All of it is from longwall mines in thick seams (This is, in fact, the only longwall mining forecasted by the model.) In contrast, all of the surface mining in this region is projected to take place in high stripping ratio reserves It is therefore not surprising that deep mining accounts for most of the production in this region: 95.4 percent in 1985 and 88.1 percent in 2000 Production from the other regions comes entirely from area mines operating in high stripping ratio areas.

APPENDIX A

MODEL STRUCTURE

The EEA coal model is formulated as a linear program and solved using the revised simplex method with Control Data Corporation's APEX-III linear programming system. The model is a cost-optimization that minimizes the cost of delivered coal across the United States subject to bounds on production available from each region at each price.

The objective function in the LP that is minimized is:

$$\sum_i \sum_j \sum_k (CP)_{ik} * P_{ijk} + \left(\sum_i \sum_l (CT)_{il} + \sum_i \sum_j \sum_m (CS)_{ijm} \right) * U_{ijm}$$

where:

$(CP)_{ik}$ = cost of producing coal from reserve characterization k in supply region i

P_{ijk} = production of coal from reserve characterization k of sulfur content j from supply region i

$(CT)_{il}$ = unit cost of shipping coal to demand region l from supply region i

$(CS)_{ijm}$ = unit cost of scrubbing coal in demand sector m (see definition below) of coal of sulfur content j that is mined in supply region i

(note: $(CS)_{ijm}$ is set to zero for demand sectors that are <u>not</u> subject to NSPS-II sulfur emissions regulations.)

U_{ijlm} = amount of coal used in demand sector m within demand region l of sulfur content j that is mined in supply region i.

Each P_{ijk} is bounded; this represents how much coal is recoverable from a particular reserve (i e., at a particular price)

$$P_{ijk} \leq S_{ijk} \quad . \quad \forall\ i,j,k$$

The only other constraints in the model are that production equals usage (i.e., supply equals demand)

$$\sum_k P_{ijk} - \sum_l \sum_m U_{ijlm} = 0. \quad \forall\ i,j$$

APPENDIX B

USERS' GUIDE TO THE COAL SUPPLY CURVE PROGRAM

This section will describe and present the various computer programs used to generate the coal supply curves. The Appendix is divided into two parts:

- o A listing of all the variables used in the mine cost program
- o The programs themselves, with accompanying explanatory material

In addition, reference should be made to Section 7, which describes the mine cost models, including all data inputs for the models. In particular, the reader's attention is directed to Tables 7-8, 7-11, and 7-13, which outline the mine cost models.

B.1 VARIABLES IN THE MINE COST MODEL

Variable	Type	Description
ADSFTCST	real scalar	Additional initial cost adjustment for shaft mines. 666000.
AMINE	integer scalar	The mine model that is used for surface mines thin seam = 1 Texas lignite = 2 Ft. Union lignite = 3 dipping seams = 4 Powder River = 5 Four Corners = 6
ANS	string scalar	Whether characterizations that are to be costed will come from terminal ("T") or file ("F")
BASE	real scalar	The production of the mine that is being used to model the reserve

BASELW	real scalar	The production of the longwall mine that is used to model longwall-mineable reserves 1500000
BASERP	real 3x3 array	The production of the various room & pillar mines used to model room & pillar-mineable reserves
BLKSIZ	real scalar	The reserve block class (1 through 5) that is contained in the reserve characterization
CASH	real scalar	The cash flow needed to start up underground mines
CLEAN	real scalar	The number of "clean tons" of coal available (which determines the energy available, whether coal is washed or not) (UG)
CLNCOST	real scalar	The unit cost of cleaning one unit of "clean" coal (UG)
CSHFLADJ	real scalar	The fraction of total investment needed as initial cash flow (UG)
DAYSINYR	integer scalar	The number of days in a year (220) -- used in productivity calculations to adjust units (UG)
DEFRI	real scalar	The deferred investment for the model mine (UG)
DEFRILW	real scalar	The deferred investment for the longwall model
DEFRIRP	real 3x3 array	The defferred investment for the various room & pillar models
DEPRFRAC	real scalar	The fraction of initial investment that is considered depreciation (UG)
DEVATSLW	real scalar	Development cost adjustment for thin seam longwall mines
DEVEL	real scalar	Development cost within initial investment (UG)
DEVELLW	real scalar	Development cost for model longwall mines

DEVELRP	real 3x3 array	Development cost for the various model room & pillar mines
DPCN	real scalar	Depreciation (UG)
DRCT	real scalar	Direct labor operating costs (UG)
DRCTLW	real scalar	Direct labor operating costs for model room & pillar mines
DRFTSHFT	integer scalar	Whether the characterization to be costed is a drift mine (1) or a shaft mine (2) (UG)
EFFCLEAN	real scalar	Fraction of raw tons remaining after washing (UG)
EFTSLW	real scalar	Fraction to correct productivity of sharply pitching longwall mines
GROSS	real scalar	Gross profit (UG)
GROWTH00	real scalar	Growth rate in productivity compounded to year 2000
GROWTH85	real scalar	Growth rate in productivity compounded to year 1985
HANDL	real 3-array	Handling factor (area)
HRSINDAY	real scalar	Number of hours in work-day (used in productivity calculations)
IFIL	filename (string)	Input file name
INDC	real scalar	Indirect operating costs (UG)
INDCFR	real scalar	Fraction of operating supplies and direct labor costs that are added to operating costs as indirect operating costs (UG)
INFLAT	real 6x2 array	Inflation factor for area mines for each (model mine, year) combination
INFLATX	real scalar	Inflation factor for contour mines
INFLAT00	real scalar	Inflation factor for underground mines in 2000

INFLAT85	real scalar	Inflation factor for underground mines in 1985
INIT	real scalar	Total initial investment (UG)
INVTXRAT	real scalar	Fraction of total initial investment that must be used for taxes and insurance
MASP	real scalar	Minimum acceptable selling price
MINTYP	string	Mine type ("A" - area, "C" - contour, "L" - longwall, "R" - room & pillar) for reserve characterization that is being costed
NUMMENLW	integer scalar	Total number of workers in longwall model mine
NUMMENRP	integer 3x3 array	Total number of workers in each room & pillar model mine
NUMUMWLW	integer scalar	Total number of union workers in each longwall model mine
NUMUMWRP	integer 3x3 array	Total number of union workers in each room & pillar model mine
OBTHK	integer	Overburden depth class for reserve characterization that is being costed (1, 2, or 3)
OBDEPTH	real 3-array	Additional initial investment for shaft mines
OFIL	filename (string)	Output file name
OHRATE	real scalar	Overhead part of operating costs (UG)
OPSUP	real scalar	Operating supplies part of operating cost (UG)
OPSUPLW	real scalar	Operating supplies for longwall model mine
OPSUPRP	real 3x3 array	Operating supplies for room & pillar model mines
OTHATSLW	real scalar	Initial investment adjustment for thin seam longwall mines
OTHR	real scalar	"Other" operating costs (UG)

OTHRI	real scalar	"Other" initial investment (UG)
OTHRILW	real scalar	"Other" investment for longwall model mine
OTHRIRP	real 3x3 array	"Other" investment for room & pillar model mines
OTHROCLW	real scalar	"Other" operating costs for longwall model mines
OTHROCRP	real 3x3 array	"Other" operating costs for room & pillar model mines
OVERB	real 6x3 array	Overburden costs for area mines by area mine model and strip ratio
PITCH	integer scalar	Pitch class for reserve characterization (1, 2, or 3)
POW	real scalar	Power & water part of operating costs (UG)
POWLW	real scalar	Power & water for longwall mine model
POWRP	real 3x3 array	Power & water for room & pillar model mines
PRCFCLN	real scalar	Clean tonnage correction for productivity (UG)
PROD	real scalar	Productivity (UG)
PRODLIMT	real scalar	Annual production limit for reserve characterization being costed
PRODLW	real 3-array	Productivity for longwall model mines by seam thickness
PRODRPM	real 3x3x6 array	Productivity for room & pillar model mines by block size, seam thickness, and supply region
RAW	real scalar	Raw tons mined (from productivity calculations)
RESVCHAR	string	Reserve characterization
REV	real scalar	Initial revenue calculation, final revenue calculation (UG)

REV1	real scalar	Initial revenue calculation (contour)
REVFAC	real 6-array	Revenue factor (area)
ROIFAC	real 6-array	Royalty factor (area)
ROYAL	real scalar	Royalty rate (used directly in UG)
ROYLEAST	real scalar	Royalty rate in Eastern U S.
ROYLWEST	real scalar	Royalty rate in Western U S
ROYR	real function	Royalty rate adjusted for area mine model -- function of ROYAL
ROYSUBTR	real 6-array	Adjustment for area mine model for royalty rates
SEAMTHIK	integer scalar	Seam thickness class of reserve characterization (1, 2, or 3)
SEVR	real scalar	Severance tax rate for reserve characterization being costed
SEVRTXRT	real 15-array	Severance tax rate for each supply region
SEVT	real function	Adjusted severance tax for area mine model
SIZFAC	real 6-array	Size factor for area mine model
SLOPE	real 3-array	Slope factor for contour mine model
SLOPNO	integer scalar	Slope class of reserve characterization being costed (1, 2, or 3) (surface)
STRIP	real 3-array	Strip ratio factor for contour mine model
STRIPRTO	integer scalar	Strip ratio class of reserve characterization being costed (1, 2, or 3) (surface)
SUBTOT	real 6-array	"Subtotal" of constant costs for area mine model
SUPLYRGN	integer scalar	Supply region of reserve characterization being costed (1 to 15)
TAXRAT	real scalar	Tax rate for UG mines in revenue calculations
TOTL	real scalar	Total investment (UG)

TOTOP	real scalar	Total operating costs (UG)
TXINS	real scalar	Taxes & insurance (UG)
UCLNCST	real scalar	Unit cleaning costs (UG)
UCOBD	real scalar	Unit shaft adjustment per unit overburden for shaft mines of initial investment
UVENTCST	real scalar	Unit ventilation cost for shaft mines, added to other initial investment
WELF	real scalar	Union welfare costs (UG)
WELF1	real 6x3 array	Old union welfare adjustment for area mines
WELF2	real 6x3 array	New union welfare adjustment for area mines
WELFCM	real scalar	Union welfare adjustment for contour mines
WLCSTHR	real scalar	Unit union welfare cost per hour (labor portion) (UG)
WLCSTON	real scalar	Unit union welfare cost per raw ton producer (production portion) (UG)
WORK	real scalar	Working capital (UG)
WRKCAPFR	real scalar	Fraction of initial investment needed for additional working capital
YEAR	integer scalar	Model year (1985 or 2000)
YEARNO	integer scalar	1985 = 1, 2000 = 2

Note: UG = Underground Mines

B.2 COAL RESERVE INPUT FILE

An input file is first prepared that describes coal reserves in the United States by supply region, sulfur content, and geological characteristic (which determines mining method). The reserve characterization is ten alphanumeric characters (FORTRAN FORMAT(A10)), described briefly as follows:

Column 1	ignored
Columns 2-3	supply region, an integer between 1 and 15, inclusive (FORMAT(I2.2))
Column 4	sulfur content, either "C" for compliance coal, "L" for low-sulfur coal, or "H" for high-sulfur coal (FORMAT(A1))
Column 5	mining method: "A" for area mines, "C" for contour mines, "L" for longwall mines, or "R" for room & pillar mines (FORMAT(A1))
Column 6	Seam thickness category: 1, 2, or 3 (FORMAT(I1))

Columns 7-10 vary depending upon whether the characterization is surface- or underground-mineable. For surface mines:

Column 7	slope category (1, 2, or 3) (FORMAT(I1))
Column 8	pitch category (1, 2, or 3) (FORMAT(I1))
Column 9	strip ratio category (1, 2, or 3) (FORMAT(I1))
Column 10	Reserve block size category (1, 2, 3, 4, or 5) (FORMAT(I1)

For underground mines:

Column 7	pitch category, as above
Column 8	reserve block size category, as above
Column 9	overburden depth category (1, 2, or 3) (FORMAT(I1))
Column 10	1 for drift mines, 2 for shaft mines (FORMAT(I1))

For the values of the geologic parameters, see Table 6-2.

On the same record (on the same line) as each reserve characterization in the input file is the annual production limit, which is the amount of coal (in billions of tons) available that can be produced in one year from that particular reserve characterization. It takes up the nine columns immediately following the characterization, and is precise to six decimal places (FORMAT(F9.6)) The FORMAT for each input record to the mine cost model is therefore:

(A1, I2.2, A2, 5I1, F9.6)

The records may look like this:

```
PO2CA1112100.004378
PO2CA1122100.598763
PO2CR1212102.897374
PO2CR1213103.854924
PO2CL1313105.281900
PO2CC1232503.403944
```

B.3 THE MINE COST PROGRAM

The mine cost program incorporates the area, contour and underground cost models. The mine cost program is written in General Electric Co.'s implementation of FORTRAN 77, the new ANSI-approved standard for FORTRAN, which replaces FORTRAN IV Practically every value in the program (even the number of working days in a year or hours in a day) are stored in files that are external to the program and read in upon execution. Thus every value within the cost model may be easily changed without touching the model itself

The mine cost model is designed to be run interactively as well as from an input file as described above. The model asks the user, upon execution, if the input will be from file or terminal, and if from file, what the input and output files are. If the user indicates terminal input, he/she simply types in any reserve characterization and the program responds with the production cost in dollars per ton This interactive feature is useful for checking particular reserve costs in both testing new model assumptions/ as to productivity, costs, etc , and in making a small number of corrections to the production costs of the running model.

For most work, however, the mine cost program will read in data from a file as specified above and output corresponding records with characterization, production cost (in dollars per ton), and production limit. The new file is FORMAT(A10, F7.2, F9.6).

The actual source code for the model follows, along with the input parameters for the cost model that are stored in their particular external files

B.4 FROM MINE COST PROGRAM TO APEX-III INPUT

B.4.1 Elimination of Duplicate Reserve Characterizations

It was found, after the mine cost program was run, that there were a number of duplicate reserve characterizations. This condition occurred because the reserves were originally estimated by state, and each state was given the correct supply region number. The program ELDPMN was written to combine the production levels of the duplicate reserve characterizations. The file that is produced from the mine cost model must first be sorted by characterization using any standard sort utility (on General Electric it is SORT***). The output from ELDPMN is formatted identically to the input (A10, F7.2, F0 6)

One manual correction was then made. It was determined that too much of the compliance coal in Central Appalachia (supply region 03) was cheaply mineable from contour mines with low strip ratios; the production limits were thus altered so that 70 percent of the surface-mineable compliance coal would have strip ratio category equal to 3. This was done with the standard text editor

B.4 2 Cost Range Program

The program MODAPMIN is used to create the ranges of costs for Appalachian and Illinois coal production. MODAPMIN reads in the file that is formatted (A10, F7 2, F9 6) and, if the characterization is from supply regions 1-5, inclusive, creates three output characterizations as follows: for underground mines, the cost that is read in upon input is treated as a "high" cost, and three characterizations are output, with costs equal to 80 percent, 90 percent, and 100 percent of the input record's cost For

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```
10 OPTION SYMBOL
20 STRING RESVCHAR
30 STRING ANS, YESNO,ANS2
40 REAL PROD
50 FILENAME IFIL,OFIL
60 INTEGER YEAR
70          INTEGER YEARNO,AMINE
80          REAL SUBTOT(6),HANDL(6),ROYSUBTR(6),ROIFAC(6),REVFAC(6)
90          REAL OVERB(6,3),SIZFAC(6,5)
100         REAL WELF1(15,5),WELF2(15,5),INFLAT(6,2)
110 REAL INFLATX,INFLAT85,INFLAT00
120 REAL WELFCM,REV1
130 REAL PRODRPH(3,3,6)
140 REAL GROWTH85,GROWTH00,GROWTHXX
150 REAL PRODLW(3)
160 REAL EFTSLW
170 REAL PRCFCLN(15)
180 REAL RAW
190 INTEGER DAYSINYR
200 INTEGER NUMMENRP(3,3)
210 INTEGER NUMMENLW
220 REAL CLEAN,EFFCLEAN,CLNCOST,UCLNCOST,WLCSTTON,WLCSTHR
230 INTEGER NUMUMWRP(3,3)
240 REAL HRSINDAY
250 REAL DEVEL,OTHRI,DEFRI
260 REAL DEVELRP(3,3),OTHRIRP(3,3),DEFRIRP(3,3)
270 REAL DEVELLW,OTHRILW,DEFRILW
280 REAL UCOBD
290 REAL OBDEPTH(3)
300 REAL ADSFICST,UVENTCST,UDCATSLW,ICATSLW
310 REAL INIT,WRKCAPFR,DEPRFRAC
320 REAL TOTL
330 REAL TXINS
340 REAL INVTXRAT
350 REAL DRCT,OPSUP,POW,BASE,OTHR
360 REAL DRCTRP(3,3),OPSUPRP(3,3),POWRP(3,3),BASERP(3,3),OTHROCRP(3,3)
370 REAL DRCTLW,OPSUPLW,POWLW,BASELW,OTHROCLW
380 REAL INDC,INDCFR
390 REAL TOTOP
400 REAL SEVR, ROYAL
410 REAL SEVRTXRT(15),ROYLEAST,ROYLWEST
420 REAL CASH, CSHFLADJ
430 REAL REV
440 REAL TAXRAT
450 REAL GROSS
460 REAL MASP
470 INTEGER SUPLYRGN
480 STRING SULCON
490 STRING MINTYP
500 INTEGER SEAMTHIK,PITCH,SLOPENO,STRIPRTO,BLKSIZ,OBTHK,DRLTSHFT
```

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```
REAL STRIP(3),SLOPL(3)
CCC *** READ INPUT VARIABLES
        PRINT, "Year?"
        INPUT, YEAR
CCC *** MINE-INDEPENDENT VALUES
        OPEN(FILE="UMINED1",UNIT=1)
        READ(FILE="UMINED1",FMT=*) (PRCPCLN(I),I=1,15)
        READ(FILE="UMINED1",FMT=*) GROWTH85,GROWTH00,EFTSLW,DAYSINYR,EFFCLEAN,UCLNCOST,HRSINDAY,WLCSTHR,WLCSTON
READ(FILE="UMINED1",FMT=*) UCOBD,ADSFTCST,UVENTCST,WRKCAPFR,DEPRFRAC,INVTXRAT
        READ(FILE="UMINED1",FMT=*) INDCFR,OHRATE,ROYLEAST,ROYLWEST,CSHFLADJ,TAXRAT
        READ(FILE="UMINED1",FMT=*) (SEVRTXRT(I),I=1,15)
        CLOSE(FILE="UMINED1")
CCC *** AREA DATA
        OPEN(FILE=-MDATA",UNIT=1)
        DO 78 I=1,6
              READ(FILE="AMDATA",FMT=*) SUBTOT(I),(OVLRB(I,J),J=1,3),HANDL(I)
              READ(FILE="AMDATA",FMT=*) (INFLAT(I,J),J=1,2),REVFAC(I),ROIFAC(I),ROYSUBTR(I)
              READ(FILE="AMDATA",FMT=*) (SIZFAC(I,J),J=1,5)
              READ(FILE="AMDATA",FMT=*) (WELF1(I,J),J=1,5)
              READ(FILE="AMDATA",FMT=*) (WELF2(I,J),J=1,5)
        78    CONTINUE
        CLOSE(FILE="AMDATA")
CCC *** COUNTOUR DATA
        OPEN(UNIT=1,FILE="CMDATA")
        READ(FILE="CMDATA",FMT=*) (SLOPE(I),I=1,3)
        READ(FILE="CMDATA",FMT=*) (STRIP(I),I=1,3)
        READ(FILE="CMDATA",FMT=*) INFLAT85,INFLAT00,WELFCM
        CLOSE(FILE="CMDATA")
CCC *** LONGWALL DATA
        OPEN(UNIT=1,FILE="LNGWLDTA")
        READ(FILE="LNGWLDTA",FMT=*) NUMMENLW,NUMUMWLW,DEVELLW,OTHRILW,DEFRILW
        READ(FILE="LNGWLDTA",FMT=*-DRCTLW,OPSUPLW,POWLW,BASELW,OTHROCLW
        READ(FILE="LNGWLDTA",FMT=*) (PRODLW(I),I=1,3)
        READ(FILE="LNGWLDTA",FMT=*) DEVATSLW,OTHATSLW
        CLOSE(FILE="LNGWLDTA")
CC-*** ROOM & PILLAR DATA
        OPEN(UNIT=1,FILE="RPDATA")
        DO 10 I=1,3
              DO 10 J=1,3
        10          READ(FILE="RPDATA",FMT=*) (PRODRPM(I,J,K),K=1,6)
        DO 15 I=1,3
        15    READ(FILE="RPDATA",FMT=*) (NUMMENRP(I,J),J=1,3)
        DO 20 I=1,3
        20    READ(FILE="RPDAT-,FMT=*) (NUMUMWRP(I,J),J=1,3)
        DO 25 I=1,3
        25    READ(FILE="RPDATA",FMT=*) (DEVELRP(I,J),J=1,3)
        DO 30 I=1,3
        30    READ(FILE="RPDATA",FMT=*) (OTHRIRP(I,J),J=1,3)
        DO 35 I=1,3
        35    READ(FILE="RPDAT-,FMT=*) (DEFRIRP(I,J),J=1,3)
```

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```
        READ(FILE="RPDATA",FMT=*) (OBDFPTH(I),I=1,3)
        DO 40 I=1,3
        40    READ(FILE="RPDATA",FMT=*) (DRCTRP(I,J),J=1,3)
        DO 45 I=1,3
        45    READ(FILE="RPDATA",FMT=*) (OPSUPRP(I,J),J=1,3)
        DO 50 I=1,3
        50    READ(FILE="RPDATA",FMT=*) (POWRP(I,J),J=1,3)
        DO 60 I=1,3
        60    READ(FILE="RPDATA",FMT=*)  (BASERP(I,J),J=1,3)
        DO 65 I=1,3
        65    READ(FILE="RPDATA",FMT=*) (OTHROCRP(I,J),J=1,3)
        CLOSE(FILE="RPDATA")
        IF(YEAR EQ 1985) THEN
              YEARNO = 1
        ELSE IF(YEAR EQ 2000) THEN
              YEARNO = 2
        ENDIF
        DO 1111 UNTIL((UPC(ANS(1 1)) EQ "F") OR (UPC(ANS(1 1)) EQ "T"))
              PRINT, "Reserve data from file or terminal?"
        1111  INPUT,ANS
        IF(UPC(ANS(1.1)) EQ "F") THEN  ,
              PRINT, "Input file?"
              INPUT,IFIL
              OPEN(FILE=IFIL,UNIT=2)
              DO 1112 UNTIL ((UPC(YESNO(1 1)) EQ "Y") OR (UPC(YESNO(1 1)) EQ "N"))
                    PRINT, "Is production data included with input file?"
              1112  INPUT, YESNO
              PRINT, "Output file name?"
              INPUT, OFIL
              OPEN(FILE=OFIL,UNIT=3)
        ENDIF
        1395  IF(ANS(1 1) EQ "F") THEN
                    IF(YESNO(1 1) EQ "Y") THEN
                          READ(FILE=IFIL,FMT=1396,END=8989) RESVCHAR,PRODLIMT
                    1396  FORMAT(A10,F9 6)
                    ELSE
                          READ(FILE=IFIL,FMT=1397,END=8990) RESVCHAR
                    1397  FORMAT(A10)
                    ENDIF
              ELSE
                    PRINT, "Reserve characterization?"
                    INPUT, RESVCHAR
              ENDIF
CCC
        CALL GETMINE(RESVCHAR,SUPLYRGN,MINTYP,SEAMTHIK,SLOPENO,PITCH,STRIPRTO,BLKSIZ,OBTHK,DRFTSHFT)
IF(MINTYP EQ "C") THEN
        IF(YEAR EQ 1985) THEN
              INFLAIX = INFLAT85
        ELSE IF (YEAR EQ 2000) THEN
              INFLAIX = INFLAT00
```

```
        ENDIF
        REV1 = EXP(1 06 + (STRIP(STRIPRTO)* 027634) -  286245 + (SLOPE(SLOPENO)* 014235) + (SLOPE(SLOPENO)* 0342534))
        IF((SUPLYRGN LE 6) AND (SUPLYRGN NE 3)) THEN
              MASP = (((REV1 - 0 8 + 1 38) * INFLATX * 1 6) + WELFCM)* 1 03
        ELSE
              MASP = ((REV1 - 0 8 + 1 38) * INFLATX * 1 6) * 1 03
        ENDIF
ELSE IF (MINTYP EQ "A") THEN
        IF(SUPLYRGN LE 7) THEN
              AMINE = 1   !     THIN SEAM
        ELSE IF(SUPLYRGN EQ 8) THEN
              AMINE = 2   !     TEXAS LIGNITE
        ELSE IF(SUPLYRGN EQ 9) THEN
              AMINE = 3   !     FT  UNION LIGNITE
        ELSE IF (SUPLYRGN GE 14) THEN
              AMINE = 6   !     FOUR CORNERS
        ELSE IF ((SUPLYRGN EQ 10) OR (SUPLYRGN EQ 11)) THEN
              AMINE = 5   !     POWDER RIVER
        ELSE
              AMINE = 4   !     DIPPING SEAMS
        ENDIF
CCC ***
CCC *** GET CORRECT ROYALTY RATE
        IF(SUPLYRGN LE 6) THEN
              ROYAL = ROYLEAST
        ELSE
              ROYAL = ROYLWEST
        ENDIF
CCC *** SELLING PRICE
CCC *** NONUNION REGIONS
        IF((SUPLYRGN EQ 3) OR (SUPLYRGN GE 7)) THEN
        MASP = ((SUBTOT(AMINE)+OVERB(AMINE,STRIPRTO)+HANDL(AMINE)-WELF1(AMINE,BLKSIZ))*INFLAT(AMINE,YEARNO)*ROYR(ROYSUBTR(AMINE)
&       *SIZFAC(AMINE,BLKSIZ))*REVFAC(AMINE)*ROIFAC(AMINE)*SEVT(SEVRTXRT(SUPLYRGN))
        ELSE
        MASP = ((SUBTOT(AMINE)+OVERB(AMINE,STRIPRTO)+HANDL(AMINE)-WELF1(AMINE,BLKSIZ))*INFLAT(AMINE,YEARNO)*ROYR(ROYSUBTR(AMINE)
&       *SIZFAC(AMINE,BLKSIZ)+WELF2(AMINE,BLKSIZ))*REVFAC(AMINE)*ROIFAC(AMINE)*SEVT(SEVRTXRT(SUPLYRGN))
        ENDIF
CCC ***
CCCCCCCCCCC
ELSE IF ((MINTYP EQ "R") OR (MINTYP EQ "L")) THEN
              IF(BLKSIZ GE 4) THEN
                    BLKSIZ = 3
              ENDIF
        IF(MINTYP EQ "R") THEN
CCC *** GET PRODUCTIVITY FROM MATRIX
      IF (SUPLYRGN GE 7) THEN
            PROD = PRODRPM(BLKSIZ,SEAMTHIK,6)
      ELSE IF (SUPLYRGN GE 5) THEN
            PROD = PRODRPM(BLKSIZ,SEAMTHIK,5)
        ELSE
```

```
                PROD = PRODRPM(BLKSIZ,SEAMTHIK,SUPLYRGN)
         ENDIF
C         MULTIPLY BY ANNUAL GROWTH FACTOR COMPOUNDED
         IF (YEAR EQ 1985) THEN
              PROD = PROD * GROWTH85
         ELSE IF (YEAR EQ 2000) THEN
              PROD = PROD * GROWTH00
         ELSE IF (GROWTHXX NE 0 ) THEN
              PROD = PROD * GROWTHXX
         ELSE
            PRINT, "No valid growth index for room & pillar mines for year", YEAR, ", zero growth assumed "
                PRINT, "Zero growth assumed for reserve", RESVCHAR
         ENDIF
      ENDIF
C NOW HANDLE PRODUCTIVITY FOR LONGWALL MINES "
      IF (MINTYP EQ "L") THEN
C         GET PRODUCTIVITY FROM MATRIX
         PROD = PRODLW(SEAMTHIK)
         IF (PITCH EQ 3) THEN
C               MULTIPLY BY EFFICIENCY OF SHARPLY PITCHING LONGWALL MINES
              PROD = PROD * EFTSLW
         ENDIF
      ENDIF
C FIND CLEAN TONNAGE CORRECTION FACTOR
      PROD = PROD * PRCFCLN(SUPLYRGN)
C FIND RAW TONS
      IF (MINTYP EQ "R") THEN
         RAW = PROD * DAYSINYR * NUMMENRP(BLKSIZ,SEAMTHIK)
      ELSE IF (MINTYP EQ "L") THEN
         RAW = PROD * DAYSINYR * NUMMENLW
      ENDIF
C FIND # OF CLEAN TONS
      CLEAN = RAW * EFFCLEAN
C FIND CLEANING COSTS
      CLNCOST = RAW * UCLNCOST
C UNION WELFARE COSTS
      IF (MINTYP EQ "R") THEN
         WELF = RAW * WLCSTON + NUMUMWRP(BLKSIZ,SEAMTHIK) * HRSINDAY * DAYSINYR * WLCSTHR
      ELSE IF (MINTYP EQ "L") THEN
         WELF = RAW * WLCSTON + NUMUMWLW * HRSINDAY * DAYSINYR * WLCSTHR
      ENDIF
C
C         CAPITAL COSTS
C
C GET VARIABLES FROM APPROPRIATE ARRAYS
      IF (MINTYP EQ "R") THEN
         DEVEL = DEVELRP(BLKSIZ,SEAMTHIK)
         OTHRI = OTHRIRP(BLKSIZ,SEAMTHIK)
         DEFRI = DEFRIRP(BLKSIZ,SEAMTHIK)
      ELSE IF (MINTYP EQ "L") THEN
```

```
           DEVEL = DEVELLW
           OTHRI = OTHRILW
           DEFRI = DEFRILW
        ENDIF
C
CCC *** CHANGE UNITS
                   DEVEL = DEVEL * 1.0E+6
                   OTHRI = OTHRI * 1.0E+6
                   DEFRI = DEFRI * 1.0E+6
C
C SHAFT MINE ADJUSTMENT
      IF (DRFTSHFT EQ 2) THEN
C         SHAFT INVESTMENT
         OTHRI = OTHRI + OBDEPTH(OBTHK) * UCOBD + ADSFTCST
C         VEENTILATION
         OTHRI = OTHRI + BLKSIZ * OBDEPTH(OBTHK) * UVENTCST
      ENDIF
CCC
CCC *** THINSEAM LONGWALL ADJUSTMENT
CCC
            IF((MINTYP EQ "L") AND (SEAMTHIK EQ 1)) THEN
                   DEVEL = DEVEL *  DEVATSLW
                   OTHRI = OTHRI - OTHATSLW
            ENDIF
CCC
C
C TOTAL INITIAL INVESTMENT
      INIT = OTHRI + DEVEL
C WORKING CAPITAL
      WORK = INIT * WRKCAPFR
C DEPRECIATION
      DPCN = INIT * DEPRFRAC
C TOTAL INVESTMENT
      TOTL = INIT + WORK + DEFRI
C TAXES & INSURANCE
      TXINS = INIT * INVTXRAT
C
C
C OPERATING COSTS
C
C GET VARIABLES
            IF (MINTYP EQ "R") THEN
         DRCT = DRCTRP(BLKSIZ,SEAMTHIK)
         OPSUP = OPSUPRP(BLKSIZ,SEAMTHIK)
         POW = POWRP(BLKSIZ,SEAMTHIK)
         BASE = BASERP(BLKSIZ,SEAMTHIK)
         OTHR = OTHROCRP(BLKSIZ,SEAMTHIK)
      ELSE IF (MINTYP EQ "L") THEN
         DRCT = DRCTLW
         OPSUP = OPSUPLW
```

```
      POW = POWLW
      BASE = BASELW
      OTHR = OTHROCLW
   ENDIF
C
CCC *** CHANGE UNITS
              DRCT = DRCT * 1.0E+6
              OPSUP = OPSUP * 1.0E+6
              POW = POW * 1.0E+6
              OTHR = OTHR * 1.0E+6
C
C OPERATING SUPPLIES ADJUSTMENT
   OPSUP = OPSUP / BASE * RAW
C INDIRECT COSTS
   INDC = (OPSUP + DRCT) * INDCFR
C TOTAL OPERATING COSTS
   TOTOP = DRCT * OHRATE + OPSUP + INDC + OTHR + POW + CLNCOST + TXINS + WELF
C
C
C      FINAL REVENUE CALCUALTION
C
C GET SEVERANCE AND ROYALTY TABLEE
   SEVR = SEVRTXRT(SUPLYRGN)
   IF (SUPLYRGN LE 6) THEN
      ROYAL = ROYLEAST
   ELSE
      ROYAL =  ROYLWEST
   ENDIF
C
C CASH FLOW
        CASH = TOTL / CSHFLADJ
C INITIAL REVENUE CALCULATION
   REV = (CASH/TAXRAT + TOTOP - DPCN) / (1 - SEVR - ROYAL)
C GROSS PROFIT
   GROSS = REV - TOTOP - DPCN - ROYAL*REV - SEVR*REV
C
C FINAL REVENUE CALCULATION
   IF(REV GE GROSS) THEN
      REV = (CASH + .75*TOTOP - .25*DPCN) / ((1 - ROYAL - SEVR) * .75)
   ELSE
      REV = (CASH + .5*TOTOP - .5*DPCN) / (.55 - .5*ROYAL - .5*SEVR)
   ENDIF
C
C MINIMUM ACCEPTABLE SELLING PRICE
C
   MASP = REV / CLEAN
ENDIF
IF(UPC(ANS(1:1)) EQ "Y") THEN
   PRINT, RESVCHAR, MASP
ELSE
```

```
      IF(UPC(YESNO(1 1)) EQ "Y") THEN
            WRITE(FILE=OFIL,FMT=1979) RESVCHAR,MASP,PRODLIMT
      1979  FORMAT(A10,F7 2,F9 6)
      ELSE
            WRITE(FILE=OFIL,FMT=1980) RESVCHAR,MASP
      1980  FORMAT(A10,F7 2)
      ENDIF
ENDIF
GO TO 1395
8989 CONTINUE
8990 CONTINUE
      CLOSE(FILE=IFIL)
      CLOSE(FILE=OFIL)
      STOP
  END
      SUBROUTINE GETMINE(RESV,SR,MT,ST,SL,PI,SP,BS,OB,DS)
      STRING RESV,MT
      INTEGERSR,ST,SL,PI,SP,BS,OB,DS
      SR = INTSTR(RESV(2 3))
      MT = RESV(5 5)
      ST = INTSTR(RESV(6.6))
      IF ((MT EQ "A") OR (MT EQ "C")) THEN
            SL = INTSTR(RESV(7.7))
            PI = INTSTR(RESV(8.8))
            SP = INTSTR(RESV(9 9))
            BS = INTSTR(RESV(10 10))
      ELSE
            PI = INTSTR(RESV(7.7))
            BS = INTSTR(RESV(8 8))
            OB = INTSTR(RESV(9 9))
            DS = INTSTR(RESV(10.10))
      ENDIF
      RETURN
      END
*********************************************************************************
C
      REAL FUNCTION ROYR(SUBTR,RATE)
C
      ROYR = (RATE-SUBTR) *  5 + 1
      RETURN
      END
C
*********************************************************************************
C
      REAL FUNCTION SEVF(RATE)
C
      SEVF = RATE* 5+1
      RETURN
      END
```

ELDPHN 03/06/80

```
10         FILENAME IFIL,OFIL
20         STRING RESV,RESV1
30         PRINT,'Input file name'
40         INPUT, IFIL
50         OPEN(UNIT=1,FILE=IFIL)
60         PRINT,'Output file name'
70         INPUT,OFIL
80         OPEN(UNIT=2,FILE=OFIL)
90         read(file=IFIL,fmt=1000) resv,cost,prod
100        1000  FORMAT(A10,F7 2,F9 6)
110CCC *** MAIN LOOP
120        10    read(file=IFIL,fmt=1000,end=9999) resv1,cost1,prod1
130              IF((RESV EQ RESV1) AND (COST EQ COST1)) THEN
140                    PROD = PROD + PROD1
150              ELSE
160        write(file=OFIL,fmt=1000) resv,cost,prod
170                    RESV = RESV1
180                    COST = COST1
190                    PROD = PROD1
200              ENDIF
210        GO TO 10
220        9999  CONTINUE
230        write(file=OFIL,fmt=1000) resv,cost,prod
240        close(file=OFIL)
250        close(file=IFIL)
260              STOP
270              END
```

MODAPMIN 03/06/80

```
10         FILENAME INFILE,OUTFILE
20         STRING PROD
30         REAL COST,LIMT
40CCC
50CCC
60CCC
70         PRINT,'Input file?'
80         INPUT,INFILE
90CCC
100        PRINT,'Output file?'
110        INPUT,OUTFILE
120CCC
130CCC
140        OPEN(FILE=INFILE,UNIT=1)
150        OPEN(FILE=OUTFILE,UNIT=2)
160CCC
170CCC
180        DO 500 UNTIL(INTSTR(PROD(2 3)) GE 6)
190        100   READ(FILE=INFILE,FMT=5,END=400) PROD,COST,LIMT
200              5     FORMAT(A10,F7.2,F9 6)
210              IF(INTSTR(PROD(2 3)) LE 5) THEN
220                    IF((PROD(5 5) EQ "A") OR (PROD(5 5) EQ "C")) THEN
230                          WRITE(FILE=OUTFILE,FMT=6) PROD,COST,LIMT/6
240                          6     FORMAT(A10,F7 2,F9 6)
250                          WRITE(FILE=OUTFILE,FMT=7) PROD(2 10),COST*1 1,LIMT/6
260                          7     FORMAT('Q',A9,F7 2,F9 6)
270                          WRITE(FILE=OUTFILE,FMT=8) PROD(2.10),COST*1 2,LIMT/6
280                          8     FORMAT('R',A9,F7 2,F9 6)
290                    ELSE
300                          3     FORMAT('M',A9,F7 2,F9 6)
310CCC
320                          WRITE(FILE=OUTFILE,FMT=3) PROD(2 10),COST*0 8,LIMT/6
330                          WRITE(FILE=OUTFILE,FMT=4) PROD(2.10),COST*0 9,LIMT/6
340                          4     FORMAT('N',A9,F7 2,F9 6)
350                          WRITE(FILE=OUTFILE,FMT=6) PROD,COST,LIMT/6
360                    ENDIF
370              ENDIF
380        500   CONTINUE
390        400   CONTINUE
400        CLOSE(FILE=OUTFILE)
410        CLOSE(FILE=INFILE)
420        STO-
    430        END
```

surface mines, the input cost is considered "low," and the three characterizations output have costs equal to 100 percent, 110 percent, and 120 percent of the input cost. The first character in the characterization, otherwise ignored, is modified so that "M" signals the 20 percent reduction, "N" signals the 10 percent reduction, "Q" signals the 10 percent increase, and "R" the 20 percent increase. A "P" as the first character signifies that no change has been made to the mining cost that has come out of the cost model.

B 4.3 Formatting Programs

The final two programs do nothing more than format the data for APEX-III processing The program UNITCNVP converts the MASP from dollars per tons to tenths-of-cents per million Btu's The input is formatted (A10, F7.2, F9.6) as above for characterization, cost, and production limit. The output is formatted (A10, F12.0, F12.3) for the same variables, expressed in the new units. The heat content of coal from each supply region is taken into account in converting "tons" to Btu's" (see Table 6-1)

Finally, the program REFMPROD is used to format the supply curves into APEX-III input format It is not essential to the running of the model, but very helpful in analyzing the output, that the supply characterizations be sorted by supply region and sulfur content, and in order of increasing price within supply region and sulfur content. This will produce, for each supply region/sulfur content, the convex supply curve that is of course necessary for meaningful results. (Note that the model will work just as well if the input to REFMPROD is not sorted, but a user will not be able to follow what is happening within each supply region/sulfur content combination since APEX-III outputs its variables in exactly the order in which they are input.) REFMPROD produces two output files, one of which contains the coefficients of the objective function and other aggregate rows for each characterization, and the other containing the bounds on each characterization: i e , the pro-

UNITCNVP   03/06/80

```
10 REAL HC(15)/12 5,13 ,13 5,13 5,11 ,11 ,13 5,7 ,6 5,8 5,8 ,9 ,12 5,11 ,9 /
20 STRING RESV
30 PRINT, 'Input file'
40 INPUT, IFIL
50 OPEN(UNIT=1,FILE=IFIL)
60 PRINT, 'Output file'
70 INPUT, OFIL
80 OPEN(UNIT=2,FILE=OFIL)
90 10       READ(FILE=IFIL,FMT=20,END=99) RESV,COSTTON,PRODTON
100 20      FORMAT(A10,F7 2,F9 6)
110         SR = INTSTR(RESV(2.3))
120         COSTBBTU = COSTTON/HC(SR)*5 E+2
130         PRODBBTU = PRODTON*HC(SR)*2 E+6
140         WRITE(FILE=OFIL,FMT=30) RESV,COSTBBTU,PRODBBTU
150 30      FORMAT(A10,F12 0,F12 3)
160         GO TO 10
170 99      CLOSE(FILE=IFIL)
180         CLOSE(FILE=OFIL)
190         STOP
200         END
```

RLFMPROD 03/06/80

```
10 STRING PROD,AGTYPE,AGMETH
20 FILENAME IFIL,OBFIL,OCFIL
30 PRINT, 'Input file'
40 INPUT, IFIL
50 OPEN(FILE=IFIL)
60 PRINT, 'Output file for bounds'
70 INPUT, OBFIL
80 OPEN(FILE=OBFIL)
90 PRINT, 'Output file for columns'
100 INPUT, OCFIL
110 OPEN(FILE=OCFIL)
120 WRITE(FILE=OCFIL,FMT=7)
130 7 FORMAT('COLUMNS')
140 WRITE(FILE=OBFIL,FMT=8)
150 8 FORMAT('BOUNDS')
160 100      READ(FILE=IFIL,FMT=10,END=999) PROD,COST,ALIM
170 10       FORMAT(A10,F12 0,F12 3)
180CCC
190          IF(PROD(5 5) EQ 'A') THEN
200                IF(PROD(9.9)  EQ '1') THEN
210                      AGMETH = 'LOWSTR'
220                ELSE
230                      AGMETH = 'HIHSTR'
240                ENDIF
250          ELSE IF(PROD(5 5) EQ 'C') THEN
260                IF(PROD(7 7) EQ '1') THEN
270                      AGMETH = 'GENTIL'
280                ELSE
290                      AGMETH = 'STEEPS'
300                ENDIF
310          ELSE IF(PROD(5 5) EQ 'R') THEN
320                IF(PROD(6 6) EQ '1') THEN
330                      AGMETH = 'THINSM'
340                ELSE
350                      AGMETH = 'THIKSM'
360                ENDIF
370          ELSE IF(PROD(5 5)  EQ 'L') THEN
380                AGMETH = 'LONGWL'
390          ENDIF
400          IF(((PROD(5 5) EQ 'A') OR (PROD(5 5) EQ 'C')) OR (PROD(5 5) EQ 'S')) THEN
410                AGTYPE = 'SURFACE'
420          ELSE
430                AGTYPE = 'UNDERGD'
440          ENDIF
450CCC
460          WRITE(FILE=OCFIL,FMT=20) PROD,PROD(2 4)
470 20       FORMAT('     ',A10,'P',A3,'XXXXXX1 0')
480          WRITE(FILE=OCFIL,FMT=40) PROD,COST
490 40       FORMAT('     ',A10,'MINEXXXXXX',F12 0)
500          IF((PROD(5 5) NE 'S') AND (PROD(5 5) NE 'U')) THEN
```

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```
      WRITE(FILE=OCFIL,FMT=50) PROD,PROD(2·3),AGMETH
      ENDIF
50    FORMAT('     ',A10,'P',A2,'X',A6,'1 0')
      WRITE(FILE=OCFIL,FMT=60) PROD,PROD(2 3),AGTYPE
60    FORMAT('     ',A10,'P',A2,A7,'1 0')
      WRITE(FILE=OBFIL,FMT=70) PROD,ALIM
70    FORMAT(' UP BND        ',A10,F12 0)
      GO TO 100
999   WRITE(FILE=OBFIL,FMT=9)
9     FORMAT('ENDATA')
      CLOSE(FILE=OBFIL)
      CLOSE(FILE=OCFIL)
      CLOSE(FILE=IFIL)
      STOP
END
```

duction limit Note that each individual reserve characterization becomes a unique variable in the linear program.

For further documentation on FORTRAN 77, APEX-III, or either the General Electric or Control Data computer systems, the reader is referred to the appropriate service bureaus

Appendix C

GEOMETRY OF THE BLOCK SIZE CALCULATION

For a given seam thickness, the elevation on the hillside necessary to give a 6, 20, or 40 mmt block size is a function of the model hill base area, height, and slope

The average slope was used to determine the rate at which the model hill tapers toward the top. The acres needed for each block size are given below:

	Seam Thickness	
	28-41"	42-119"
6 mmt	1,111 acres	666 acres
20 mmt	3,203 acres	2,222 acres
40 mmt	7,407 acres	4,444 acres

Since the model hill is considered cone-shaped with circular planar sections, the radius can be calculated for each of the acreages above.

	Seam Thickness	
	28-41"	42-119"
6 mmt	3,924'	3,038'
20 mmt	6,664'	5,550'
40 mmt	10,134'	7,849'

Along with the average slope, these distances were used to calculate the vertical separation between different potential block sizes The percentage of the height of the model hill allocated to each block size was used to estimate the distribution of reserves into block sizes. For example, the distribution of reserves by block size for an area with an average base of 4,000 acres, with a relief of 1000' and slope equal to

20° would be calculated in the following manner (the radius of a circular area equal to 4,000 acres being 7,447')

for reserves 28-41 inches thick -

$$(\tan 20°) \times (7{,}447' - 6{,}664') = 284'$$

	Distribution by Block Size	
	Feet	Percentage
6 mmt	716	72
20 mmt	284	28
Total	1,000	100

Thus, the distribution of outcropping 28-41 inch thick reserves to mine blocks in this county group would be 28% to the 20 mmt block size and 72% to the 6 mmt block size